Exhibit A

Proposed FAC-013-2 Reliability Standard and proposed definitions

Definitions of Terms Used in Standard

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

Near-Term Transmission Planning Horizon: The transmission planning period that covers Year One through five.

Year One: The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For an assessment started in a given calendar year, Year One includes the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One includes the forecasted peak Load period for either 2012 or 2013.

A. Introduction

1. **Title: Assessment of Transfer Capability for the Near-Term Transmission Planning Horizon**

2. **Number:** FAC-013-2

3. **Purpose:** To ensure that Planning Coordinators have a methodology for, and perform an annual assessment to identify potential future Transmission System weaknesses and limiting Facilities that could impact the Bulk Electric System's (BES) ability to reliably transfer energy in the Near-Term Transmission Planning Horizon..

4. **Applicability:**

   4.1. Planning Coordinators

5. **Effective Date:**

   In those jurisdictions where regulatory approval is required, the latter of either the first day of the first calendar quarter twelve months after applicable regulatory approval or the first day of the first calendar quarter six months after MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-2 are effective.

   In those jurisdictions where no regulatory approval is required, the latter of either the first day of the first calendar quarter twelve months after Board of Trustees adoption or the first day of the first calendar quarter six months after MOD-001-1, MOD-028-1, MOD-029-1 and MOD-030-2 are effective.

B. Requirements

R1. Each Planning Coordinator shall have a documented methodology it uses to perform an annual assessment of Transfer Capability in the Near-Term Transmission Planning Horizon (Transfer Capability methodology). The Transfer Capability methodology shall include, at a minimum, the following information: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. Criteria for the selection of the transfers to be assessed.

1.2. A statement that the assessment shall respect known System Operating Limits (SOLs).

1.3. A statement that the assumptions and criteria used to perform the assessment are consistent with the Planning Coordinator's planning practices.

1.4. A description of how each of the following assumptions and criteria used in performing the assessment are addressed:

1.4.1. Generation dispatch, including but not limited to long term planned outages, additions and retirements.

1.4.2. Transmission system topology, including but not limited to long term planned Transmission outages, additions, and retirements.

1.4.3. System demand.

1.4.4. Current approved and projected Transmission uses.

1.4.5. Parallel path (loop flow) adjustments.

1.4.6. Contingencies

1.4.7. Monitored Facilities.

1.5. A description of how simulations of transfers are performed through the adjustment of generation, Load or both.

R2. Each Planning Coordinator shall issue its Transfer Capability methodology, and any revisions to the Transfer Capability methodology, to the following entities subject to the following: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]

2.1. Distribute to the following prior to the effectiveness of such revisions:

2.1.1. Each Planning Coordinator adjacent to the Planning Coordinator's Planning Coordinator area or overlapping the Planning Coordinator's area.

2.1.2. Each Transmission Planner within the Planning Coordinator's Planning Coordinator area.

2.2. Distribute to each functional entity that has a reliability-related need for the Transfer Capability methodology and submits a request for that methodology within 30 calendar days of receiving that written request.

R3. If a recipient of the Transfer Capability methodology provides documented concerns with the methodology, the Planning Coordinator shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the Transfer Capability methodology and, if no change will be made to that Transfer Capability methodology, the reason why. [Violation Risk Factor: Lower][Time Horizon: Long-term Planning]

R4. During each calendar year, each Planning Coordinator shall conduct simulations and document an assessment based on those simulations in accordance with its Transfer Capability methodology for at least one year in the Near-Term Transmission Planning Horizon. [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]

R5. Each Planning Coordinator shall make the documented Transfer Capability assessment results available within 45 calendar days of the completion of the assessment to the recipients of its Transfer Capability methodology pursuant to Requirement R2, Parts 2.1 and Part 2.2. However, if a functional entity that has a reliability related need for the results of the annual assessment of the Transfer Capabilities makes a written request for such an assessment after the completion of the assessment, the Planning Coordinator shall make the documented Transfer Capability assessment results available to that entity within 45 calendar days of receipt of the request [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]

R6. If a recipient of a documented Transfer Capability assessment requests data to support the assessment results, the Planning Coordinator shall provide such data to that entity within 45 calendar days of receipt of the request. The provision of such data shall be subject to the legal and regulatory obligations of the Planning Coordinator's area regarding the disclosure of confidential and/or sensitive information. [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]

C. Measures

M1. Each Planning Coordinator shall have a Transfer Capability methodology that includes the information specified in Requirement R1.

M2. Each Planning Coordinator shall have evidence such as dated e-mail or dated transmittal letters that it provided the new or revised Transfer Capability methodology in accordance with Requirement R2

M3. Each Planning Coordinator shall have evidence, such as dated e-mail or dated transmittal letters, that the Planning Coordinator provided a written response to that commenter in accordance with Requirement R3.

M4. Each Planning Coordinator shall have evidence such as dated assessment results, that it conducted and documented a Transfer Capability assessment in accordance with Requirement R4.

M5. Each Planning Coordinator shall have evidence, such as dated copies of e-mails or transmittal letters, that it made its documented Transfer Capability assessment available to the entities in accordance with Requirement R5.

M6. Each Planning Coordinator shall have evidence, such as dated copies of e-mails or transmittal letters, that it made its documented Transfer Capability assessment data available in accordance with Requirement R6.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Data Retention

The Planning Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Planning Coordinator shall have its current Transfer Capability methodology and any prior versions of the Transfer Capability methodology that were in force since the last compliance audit to show compliance with Requirement R1.
- The Planning Coordinator shall retain evidence since its last compliance audit to show compliance with Requirement R2.
- The Planning Coordinator shall retain evidence to show compliance with Requirements R3, R4, R5 and R6 for the most recent assessment.
- If a Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time periods specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Planning Coordinator has a Transfer Capability methodology but failed to address one or two of the items listed in Requirement R1, Part 1.4.	The Planning Coordinator has a Transfer Capability methodology, but failed to incorporate one of the following Parts of Requirement R1 into that methodology: • Part 1.1 • Part 1.2 • Part 1.3 • Part 1.5 OR The Planning Coordinator has a Transfer Capability methodology but failed to address three of the items listed in Requirement R1, Part 1.4.	The Planning Coordinator has a Transfer Capability methodology, but failed to incorporate one of the following Parts of Requirement R1 into that methodology: • Part 1.1 • Part 1.2 • Part 1.3 • Part 1.5 OR The Planning Coordinator has a Transfer Capability methodology but failed to address four of the items listed in Requirement R1, Part 1.4.	The Planning Coordinator did not have a Transfer Capability methodology. OR The Planning Coordinator has a Transfer Capability methodology, but failed to incorporate one of the following Parts of Requirement R1 into that methodology: • Part 1.1 • Part 1.2 • Part 1.3 • Part 1.5 OR The Planning Coordinator has a Transfer Capability methodology but failed to address more than four of the items listed in Requirement R1, Part 1.4.

R2	The Planning Coordinator notified one or more of the parties specified in Requirement R2 of a new or revised Transfer Capability methodology after its implementation, but not more than 30 calendar days after its implementation. OR The Planning Coordinator provided the transfer Capability methodology more than 30 calendar days but not more than 60 calendar days after the receipt of a request.	The Planning Coordinator notified one or more of the parties specified in Requirement R2 of a new or revised Transfer Capability methodology more than 30 calendar days after its implementation, but not more than 60 calendar days after its implementation. OR The Planning Coordinator provided the Transfer Capability methodology more than 60 calendar days but not more than 90 calendar days after receipt of a request	The Planning Coordinator notified one or more of the parties specified in Requirement R2 of a new or revised Transfer Capability methodology more than 60 calendar days, but not more than 90 calendar days after its implementation. OR The Planning Coordinator provided the Transfer Capability methodology more than 90 calendar days but not more than 120 calendar days after receipt of a request.	The Planning Coordinator failed to notify one or more of the parties specified in Requirement R2 of a new or revised Transfer Capability methodology more than 90 calendar days after its implementation. OR The Planning Coordinator provided the Transfer Capability methodology more than 120 calendar days after receipt of a request.
R3	The Planning Coordinator provided a documented response to a documented concern with its Transfer Capability methodology as required in Requirement R3 more than 45 calendar days, but not more than 60 calendar days after receipt of the concern.	The Planning Coordinator provided a documented response to a documented concern with its Transfer Capability methodology as required in Requirement R3 more than 60 calendar days, but not more than 75 calendar days after receipt of the concern.	The Planning Coordinator provided a documented response to a documented concern with its Transfer Capability methodology as required in Requirement R3 more than 75 calendar days, but not more than 90 calendar days after receipt of the concern.	The Planning Coordinator failed to provide a documented response to a documented concern with its Transfer Capability methodology as required in Requirement R3 by more than 90 calendar days after receipt of the concern. OR The Planning Coordinator failed to respond to a documented concern with its Transfer Capability methodology.

R4.	The Planning Coordinator conducted a Transfer Capability assessment outside the calendar year, but not by more than 30 calendar days.	The Planning Coordinator conducted a Transfer Capability assessment outside the calendar year, by more than 30 calendar days, but not by more than 60 calendar days.	The Planning Coordinator conducted a Transfer Capability assessment outside the calendar year, by more than 60 calendar days, but not by more than 90 calendar days.	The Planning Coordinator failed to conduct a Transfer Capability assessment outside the calendar year by more than 90 calendar days. OR The Planning Coordinator failed to conduct a Transfer Capability assessment.

R5	The Planning Coordinator made its documented Transfer Capability assessment available to one or more of the recipients of its Transfer Capability methodology more than 45 calendar days after the requirements of R5,, but not more than 60 calendar days after completion of the assessment.	The Planning Coordinator made its Transfer Capability assessment available to one or more of the recipients of its Transfer Capability methodology more than 60 calendar days after the requirements of R5, but not more than 75 calendar days after completion of the assessment.	The Planning Coordinator made its Transfer Capability assessment available to one or more of the recipients of its Transfer Capability methodology more than 75 calendar days after the requirements of R5, but not more than 90 days after completion of the assessment.	The Planning Coordinator failed to make its documented Transfer Capability assessment available to one or more of the recipients of its Transfer Capability methodology more than 90 days after the requirements of R5. OR The Planning Coordinator failed to make its documented Transfer Capability assessment available to any of the recipients of its Transfer Capability methodology under the requirements of R5.
R6	The Planning Coordinator provided the requested data as required in Requirement R6 more than 45 calendar days after receipt of the request for data, but not more than 60 calendar days after the receipt of the request for data.	The Planning Coordinator provided the requested data as required in Requirement R6 more than 60 calendar days after receipt of the request for data, but not more than 75 calendar days after the receipt of the request for data.	The Planning Coordinator provided the requested data as required in Requirement R6 more than 75 calendar days after receipt of the request for data, but not more than 90 calendar days after the receipt of the request for data.	The Planning Coordinator provided the requested data as required in Requirement R6 more than 90 after the receipt of the request for data. OR The Planning Coordinator failed to provide the requested data as required in Requirement R6.

E. Regional Variances

None.

F. Associated Documents

Version History

Version	Date	Action	Change Tracking
1	08/01/05	1. Changed incorrect use of certain hyphens (-) to “en dash (–).” 2. Lower cased the word “draft” and “drafting team” where appropriate. 3. Changed Anticipated Action #5, page 1, from “30-day” to “Thirty-day.” 4. Added or removed “periods.”	01/20/05
2	01/23/11	Approved by BOT	

Exhibit B

Implementation Plan for the proposed FAC-013-2 Reliability Standard

Implementation Plan for Standard FAC-013-2
Assessment of Transfer Capability for the Near-term Transmission Planning Horizon

Prerequisite Approvals

There are no Standard Authorization Requests (SARs) that must be implemented before this standard can be implemented.

FAC-013-2 cannot be implemented before the following standards become effective:

- MOD-001-1 — Available Transmission System Capability
- MOD-028-1— Area Interchange Methodology
- MOD-029-1 — Rated System Path Methodology
- MOD-030-2 — Flowgate Methodology

New or Modified Definitions

The following definitions shall become effective when FAC-013-2 becomes effective:

Near-Term Transmission Planning Horizon: The transmission planning period that covers years one through five.

Year One: The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For the Planning Assessment started in a given calendar year, Year One includes the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One includes the forecasted peak Load period for either 2012 or 2013.

Modified Standards

FAC-012-1 and FAC-013-1 should be retired when FAC-013-2 becomes effective.

FAC-012-1 – Transfer Capability Methodology

FAC-013-1 – Establish and Communicate Transfer Capabilities

Compliance with Standards

Once the standard becomes effective, the responsible entity identified in the applicability section of the standard must comply with the requirements. This includes:

- Planning Coordinator

Proposed Effective Date

In those jurisdictions where regulatory approval is required, the latter of either the first day of the first calendar quarter twelve months after applicable regulatory approval or the first day of the first calendar quarter six months after MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-2 are effective.

In those jurisdictions where no regulatory approval is required, the latter of either the first day of the first calendar quarter twelve months after Board of Trustees adoption or the first day of the first calendar quarter six months after MOD-001-1, MOD-028-1, MOD-029-1 and MOD-030-2 are effective.

Exhibit C

Standard Drafting Team Roster

Drafting Team Roster

FAC Order 729

Project 2010-10 — FAC 729 DT

Chairman	Robert Pierce	Duke Energy Carolina
	Jeremy Bennett	Southern Company Transmission Company
	Robert A. Birch — Staff Engineer	Florida Power & Light Co.
	William Harm — Senior Consultant	PJM Interconnection, LLC
	Ross Kovacs — Trans. Strategic Coordinator	Georgia Transmission Corporation
	Narinder Saini	Entergy Services, Inc.
NERC Staff	Darrel Richardson — Standards Development Coordinator	North American Electric Reliability Corporation
NERC Staff	Joseph Krisiak — Standards Development Advisor	North American Electric Reliability Corporation

Exhibit D

Complete Development Record of the proposed FAC-013-2
and Implementation Plan

Project 2010-10
FAC Order 729

Status:
FAC-013-2 and its associated implementation plan and VRFs and VSLs, and new definitions for Near-term Planning Horizon and Year One were approved by the Board of Trustees on January 24, 1011.

Purpose / Industry Need:
In Order 729, FERC ruled that the ATC standards developed in Project 2006-07 did not completely address the topics covered in FAC-012 and -013. Accordingly, the FERC denied the portions of the implementation plan that would have retied these standards, and instead directed changes to the FAC standards to be made and submitted back to the FERC no later than 60 days prior to the effective date of the standards. This SAR is being created in response to the FERC Order.

Draft	Action	Dates	Results	Consideration of Comments
FAC-013-2 Clean(50) | Redline to Last Posting(51) **Implementation Plan** Clean(48) | Redline to Last Posting(49) **Last Approved Versions of Standards** FAC-012-1(47) FAC-013-1(46)	**Recirculation Ballot** Info(52) | Vote>>	January 14-23, 2011	Summary(54) Full Record(53)	
FAC-013-2 Clean(36) | Redline to Last Posting(37) Implementation Plan Clean(34) | Redline to Last Posting(35) **Supporting Material:** Comment Form (Word)(33) White Paper(32)	Successive Ballot & Non-Binding VRF.VSL Poll Info(39) |Vote>>	**Successive Ballot** December 30 - January 8, 2011	Summary(42) Full Record(41) Non-Binding Poll Results(40)	**Successive Ballot** Consideration of Comments(45) **Non-Binding Poll** Consideration of Comments(44)

Mapping Document(31) Last Approved Versions of Standards FAC-012-1(30) FAC-013-1(29)	Comment Period Info>>(38) Submit Comments>>	**Comment Period** December 10 - January 8, 2011		**Comment Period** Consideration of Comments(43)
FAC-013-2 Clean(19) | Redline to Last Posting(20) Implementation Plan Clean(17) | Redline to Last Posting(18) **Supporting Material:** Comment Form (Word)(16) White Paper(15) Mapping Document(14) VRF and VSL Justification(13) Last Approved Versions of Standards FAC-012-1(12) FAC-013-1(11)	Initial Ballot & Non-Binding VRF/VSL Poll Vote>> | Info>>(22)	October 20 - November 3, 2010 (closed)	Summary(26) Full Record(25) Non-Binding Poll Results(24)	**Initial Ballot** Consideration of Comments(28) **Non-binding Poll** Consideration of Comments(27)
	Formal 45-day Comment Period Submit Comments>> Info>> (21)	September 20 - November 3, 2010 (closed)		**Comment Period** Consideration of Comments>>(23)
FAC-013-2 Clean(6) | Redline to Last Approval(7) Implementation Plan(5) SAR(4) **Supporting Material:** Comment Form (Word)(3)	Comment Period Submit Comments>> Info>>(8)	03/15/10 - 04/29/10 (closed)	Comments Received>>(9)	Consideration of Comments>(10)
Nomination Form (Word) (1)	Nomination Period Submit Nomination>> Info>>(2)	03/15/10 - 03/26/10 (closed)		

To download a file click on the file using your right mouse button, then save it to your computer in a directory of your choice.

Unofficial Nomination Form for the Drafting Team for FAC-012-1 and FAC-013-1 Revisions for Order 729 — Project 2010-10

Please **DO NOT** use this form. Please use the electronic nomination form located at the link below by **March 26, 2010**. If you have any questions, please contact Andy Rodriquez at andy.rodriquez@nerc.net or by telephone at 202-383-2629.

http://www.nerc.com/filez/standards/Project2010-10_FAC_Order_729.html

By submitting the following information you are indicating your willingness and agreement to actively participate in the Drafting Team meetings if appointed to the Drafting Team by the Standards Committee. This means that if you are appointed to the DT you are expected to attend all (or at least the vast majority) of the face-to-face DT meetings as well as participate in all the DT meetings held via conference calls and failure to do so shall result in your removal from the DT.

Name:	
Organization:	
Address:	
Telephone:	
E-mail:	

Project 2010-10 - FAC-012-1 and FAC-013-1 Revisions for Order 729: The purpose of the SAR and standard changes is to address FERC directives in Order 729. NERC has asked FERC for clarification on those directives, and while waiting for formal clarification from FERC, has interpreted those directives as follows:

FAC-012-1 and FAC-013-1 changes:

(1) must address the Planning Horizon to ensure continuity with the ATC-related MOD standards; (2) should not address the Operating Horizon, because the ATC-related MOD standards already address this area; (3) should not delegate oversight and responsibility for this standard to Regional Entities, but rather do so at the ERO level; (4) must not conflict with the ATC-related MOD standards; and (5) must include Violation Risk Factors (“VRF”) and Violation Severity Levels (“VSL”).

Please briefly describe your experience and qualifications directly related to the issues to be addressed by this Drafting Team. We are seeking a diverse group of individuals who have working knowledge of the new ATC-related MOD standards and individuals with expertise in developing and using transfer capabilities in the planning horizon.

Experience in developing standards inside or outside (i.e., IEEE, NAESB, ANSI, etc.) of the NERC process is beneficial, but is not required, and should be highlighted in the information submitted if applicable.

Are you currently a member of any NERC or Regional Entity SAR or standard drafting team? If yes, please list each team here. ☐ No ☐ Yes:
Have you previously worked on any NERC or Regional Entity SAR or standard drafting teams? If yes, please list them here. ☐ No ☐ Yes:

Please identify the NERC Reliability Region(s) in which your company operates and for which you are able to represent your company's position relative to the applicable issues while serving on the SAR drafting team:			
☐ ERCOT ☐ FRCC	☐ MRO ☐ NPCC	☐ RFC ☐ SERC	☐ SPP ☐ WEC
☐ Not Applicable or None of the Above			

Please identify the Industry Segment(s) for which you are able to represent on behalf of your company while serving on the SAR drafting team:	
☐	– Transmission Owners
☐	– RTOs and ISOs
☐	3 — Load-serving Entities
☐	4 — Transmission-dependent Utilities
☐	5 — Electric Generators
☐	Electricity Brokers, Aggregators, and Marketers

☐	7 — Large Electricity End Users
☐	8 — Small Electricity End Users
☐	Federal, State, and Provincial Regulatory or other Government Entities
☐	Regional Reliability Organizations and Regional Entities
☐	Not applicable

Which of the following Functional Entities[1] do you have expertise or responsibilities for which you are able to represent on behalf of your company while serving on the SAR drafting team:

☐ Balancing Authority	☐ Planning Coordinator
☐ Compliance Enforcement Authority	☐ Transmission Operator
☐ Distribution Provider	☐ Transmission Owner
☐ Generator Operator	☐ Transmission Planner
☐ Generator Owner	☐ Transmission Service Provider
☐ Interchange Authority	☐ Purchasing-selling Entity
☐ Load-serving Entity	☐ Resource Planner
☐ Market Operator	☐ Reliability Coordinator

Please provide the names and contact information for two references who could attest to your technical qualifications and your ability to work well in a group which you give us permission to contact in the event it is deemed necessary to do so.

Name and Title:		Office Telephone:	
Organization:		E-mail:	
Name and Title:		Office Telephone:	
Organization:		E-mail:	

[1] These functions are defined in the NERC Functional Model, which is available on the NERC Web site.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Drafting Team Nomination and Standards Authorization Request (SAR) Comment Periods Open Project 2010-10: FAC Order 729

Now available at: http://www.nerc.com/filez/standards/Project2010-10_FAC_Order_729.html

Nominations for Drafting Team (through March 26, 2010)

The Standards Committee is seeking industry experts to serve on the FAC Order 729 Drafting Team (see project background below). The drafting team will work on both SAR and standard development.

If you are interested in serving on this drafting team, please complete this electronic nomination form **by March 26, 2010**.

Comment Period (through April 29, 2010)

The Standards Committee has posted a proposed SAR and draft standard FAC-013-2 — Planning Transfer Capability for a 45-day comment period **ending on April 29, 2010**.

Please use this electronic form to submit comments If you experience any difficulties in using the electronic form, please contact Lauren Koller at Lauren.Koller@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page (see project background below).

Project Background

The purpose of this project is to address FERC directives from Order 729 related to FAC-012-1 and FAC-013-1. The drafting team for Project 2006-07: ATC/TTC/AFC and CBM/TRM Revisions proposed the retirement of FAC-012 and FAC-013, believing that these standards had been effectively superseded four standards developed in the project (MOD-001, MOD-028, MOD-029, and MOD-030). In Order 729, FERC ruled that the standards developed in Project 2006-07 did not completely address the topics covered in FAC-012 and FAC-013 and did not fully address the associated directives from Order 693. Accordingly, FERC denied the portions of the implementation plan that would have retired these standards, and directed NERC to use the standards development process to make changes to the FAC standards and file those changes with FERC no later than 60 days prior to the effective date of the standards approved in Order 729.

Further details are included in the SAR and comment form posted on the project page:
http://www.nerc.com/filez/standards/Project2010-10_FAC_Order_729.html

Standards Development Process

The Reliability Standards Development Procedure contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance,
please contact Shaun Streeter at shaun.streeter@nerc.net or at 609.452.8060.

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Unofficial Comment Form for Project 2010-10 — Modifications to FAC-012 and FAC-013 for Order 729 — SAR and Draft FAC-013 Standard

Please **DO NOT** use this form. Please use the electronic comment form located at the link below to submit comments on the proposed SAR and modifications proposed FAC-013-2 — Planning Transfer Capability. Comments must be submitted by **April 29, 2010**. If you have questions please contact Andy Rodriquez at andy.rodriquez@nerc.net or by telephone at 202-383-2629.

http://www.nerc.com/filez/standards/Project2010-10_FAC_Order_729.html

Background Information:
The SAR for Project 2010-10 – Modifications to FAC-012 and FAC-013 for Order 729 proposes modifications to the following standards:

- FAC-012-1 — Transfer Capability Methodology
- FAC-013-1 — Establish and Communicate Transfer Capabilities

In Order 729, FERC ruled that the ATC standards developed in Project 2006-07 did not completely address the topics covered in FAC-012 and -013 and did not fully address the associated directives from Order 693. Accordingly, FERC denied the portions of the implementation plan that would have retired these standards, and instead directed NERC to use the standards development process to make changes to the FAC standards and file those changes with FERC no later than 60 days prior to the effective date of the standards, which is currently believed to be on or after April 1, 2011 (requiring the proposed changes to be filed on or before January 31, 2011).

NERC has an obligation to address FERC's directives. It is the intent to identify all the applicable FERC directives in the SAR. Additionally, the SAR Requestor has developed a proposed draft standard that attempts to address the applicable FERC directives. Please review the SAR, the associated FERC directives, and the proposed draft standard in their entirety and then answer the following questions by using the electronic comment form.

1. Do you agree that the SAR fully addresses the applicable directives from FERC Order 693 and Order 729?

   ☐ Yes
   ☐ No
   Comments:

2. Do you agree with the scope of the proposed standards action?

   ☐ Yes
   ☐ No
   Comments:

3. Do you agree that the Planning Coordinator is the only functional entity that should have requirements assigned to them as part of this project? If not, please identify to whom the standard should apply and why.

   ☐ Yes

☐ No

Comments:

4. If you are aware of the need for a regional variance or business practice that we should consider with this SAR, please identify it here.

   Regional Variance:

   Business Practice:

   Comments:

5. If you have any other comments on this SAR that you have not already provided in response to the prior questions, please provide them here.

   Comments:

6. The draft standard proposes two new definitions.

   Planning Transfer Capability (PTC): A forecast of the transfer capability between areas that is used in the Planning Horizon when performing planning analyses.

   Planning Transfer Capability Implementation Document (PTCID): A document that describes the implementation of a method for calculating PTC, and provides information related to a Planning Coordinator's calculation of PTC.

   Do you agree with the proposed definitions in the draft standard?

   ☐ Yes

   ☐ No

   Comments:

7. The proposed purpose statement in the draft standard is:

   To ensure that Planning Coordinators calculate Planning Transfer Capabilities using an established method such that those Transfer Capabilities can be used effectively in the reliable planning of the Bulk Electric System (BES).

   Do you agree with this purpose? If not, please identify to whom the standard should apply.

   ☐ Yes

   ☐ No

   Comments:

8. The draft standard proposes to merge FAC-012 and FAC-013. Do you agree with this approach? If not, please suggest an alternate approach.

   ☐ Yes

   ☐ No

   Comments:

9. Does the draft standard adequately address the applicable FERC directives (located in the SAR)? If not, please identify what else is needed.

   ☐ Yes

☐ No

Comments:

10. Do you agree with the measures in the standard (section C)? If not, please state specific reasons why not.

    ☐ Yes

    ☐ No

    Comments:

11. Do you agree with the compliance elements in the standard (Violation Risk Factors, Time Horizons, Violation Severity Levels, and the remainder of section D)? If not, please state specific reasons why not.

    ☐ Yes

    ☐ No

    Comments:

12. Are you aware of any conflicts between the proposed standards and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

    ☐ Yes

    ☐ No

    Comments:

13. Please provide any other comments (that you have not already provided in response to the questions above) that you have on the proposed standard.

    Comments:

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Standard Authorization Request Form

Title of Proposed Project: FAC-012, FAC-013 Revisions for Order 729	
Request Date: March 3, 2010	
Approved by Standards Committee: March 11, 2010	

SAR Requester Information	**SAR Type** (*Check a box for each one that applies.*)	
Name: NERC Staff	☐	New Standard
Primary Contact NERC Staff: Andrew Rodriquez	☒	Revision to existing Standards FAC-012-1 — Transfer Capability Methodology FAC-013-1 — Establish and Communicate Transfer Capabilities
Telephone 609-452-8060 Fax	☐	Withdrawal of existing Standard
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Purpose

Address FERC directives from Order 729 Related to FAC-012-1 and FAC-013-1.

Industry Need

In Order 729, FERC ruled that the ATC standards developed in Project 2006-07 did not completely address the topics covered in FAC-012 and -013. Accordingly, the FERC denied the portions of the implementation plan that would have retied these standards, and instead directed changes to the FAC standards to be made and submitted back to the FERC no later than 60 days prior to the effective date of the standards. This SAR is being created in response to the FERC Order.

Brief Description

In Project 2006-07 ("Transfer Capabilities: ATC-TTC-CBM-TRM"), the ATC-TTC-CBM-TRM Drafting Team (ATCT DT) proposed the retirement of FAC-012 and -013, believing that these standards had been effectively superseded by four of the ATC standards developed in Project 2006-07 (MOD-001, MOD-028, MOD-029, and MOD-030). In Order 729, FERC ruled that the ATC standards did not completely address the topics covered in FAC-012 and -013, and directed changes to the FAC standards to eliminate redundancies while at the same time improving the other parts of the FAC standards that were not addressed by the ATC standards. Specifically, the Commission directed:

> "…the ERO to develop modifications to FAC-012-1 and FAC-013-1 to comply with the relevant directives of Order No. 693 and, as otherwise necessary, to make the requirements of those Reliability Standards consistent with those of the MOD Reliability Standards approved herein as well as this Final Rule. These modifications should also remove redundant provisions for the calculation of transfer capability addressed elsewhere in the MOD Reliability Standards. In making these revisions, the ERO should consider the development of a methodology for calculation of inter-regional and intra-regional transfer capabilities."

Based on the effective date of the Order, it is expected that these modifications will be due on or around January 31, 2011.

Detailed Description

This SAR proposes to retire FAC-012-1, and modify FAC-013-1. Below are excerpts from documents relevant to the SAR.

From Order 729:

278. (In the NOPR) The Commission also proposed to not grant NERC's request to withdraw FAC-012-1, nor approve the retirement of FAC-013-1. With respect to these two Reliability Standards, the Commission disagreed with NERC that they are wholly superseded by the MOD Reliability Standards addressed in these proceeding. The Commission noted that, under FAC-012-1, reliability coordinators and planning authorities would be required to document the methodology used to establish inter-regional and intra-regional transfer capabilities and to state whether the methodology is applicable to the planning horizon or the operating horizon. The Commission also noted that, under FAC-013-1, reliability coordinators and planning authorities are required to establish a set of inter-regional and intra-regional transfer capabilities that are consistent with the methodology documented under FAC-012-1, which could require the calculation of transfer capabilities for both the planning horizon and the operating horizon. The Commission posited that these FAC Reliability Standards were necessary because the proposed MOD Reliability Standards provide only for the calculation of available transfer capability and its components, including total transfer capability, in the operating horizon. Thus, the Commission stated, the proposed MOD Reliability Standards do not govern the calculation of transfer capabilities in the planning horizon, i.e., beyond 13 months in the future.

279. In Order No. 693, the Commission approved FAC-013-1, but declined to approve or remand FAC-012-1. The Commission expressed concern that FAC-012-1 merely required the documentation of a transfer capability methodology without providing a framework for that methodology including data inputs and modeling assumptions. The Commission also expressed concern that the criteria used to calculate transfer capabilities for use in determining available transfer capability must be identical to those used in planning and operating the system. The Commission directed the ERO to modify FAC-012-1 to provide a framework for the transfer capability calculation methodology that takes account of the need for consistency in the criteria used to calculate transfer capabilities.

289. Consistent with its NOPR proposal, the Commission finds that NERC has not addressed the requirements of Order No. 693 with regard to the calculation of transfer capabilities in the planning horizon. In Order No. 693 the Commission expressed concern that the criteria used to calculate transfer capabilities for use in determining available transfer capability must be identical to those used in planning and operating the system. As EEI observes, in Order No. 890, the Commission offered, as an example, a possible

definition of the operating horizon as the day-ahead and pre-scheduling periods and the planning horizon as anything beyond the operating horizon. However, NERC has already defined the near-term planning horizon as years one through five in sub-requirement R1.2 of TPL-005. The Commission believes that this definition should be consistent throughout the Reliability Standards.

290. The Commission recognizes that the calculation of transfer capabilities in the planning horizon (years one through five) may not be so accurate to support long-term scheduling of the transmission system but we do believe that such forecasts will be useful for long-term planning, in general, by measuring sufficient long-term capacity needed to ensure the reliable operation of the Bulk-Power System. Although regional planning authorities have developed similar efforts in response to Order No. 890, we believe that the requirements imposed by FAC-012 and FAC-013 need not be duplicative of those existing efforts and, by contrast, should be focused on improving the long-term reliability of the Bulk-Power System pursuant to the ERO's Reliability Standards. We believe that these responsibilities would be appropriately assigned to the planning coordinator and not the reliability coordinator.

291. The Commission hereby adopts its NOPR proposal to deny NERC's request to withdraw FAC-012-1 and retire FAC-013-1. Instead, pursuant to section 215(d)(5) of the FPA and section 39.5(f) of our regulations, the Commission directs the ERO to develop modifications to FAC-012-1 and FAC-013-1 to comply with the relevant directives of Order No. 693 and, as otherwise necessary, to make the requirements of those Reliability Standards consistent with those of the MOD Reliability Standards approved herein as well as this Final Rule. These modifications should also remove redundant provisions for the calculation of transfer capability addressed elsewhere in the MOD Reliability Standards. In making these revisions, the ERO should consider the development of a methodology for calculation of inter-regional and intra-regional transfer capabilities. The Commission accepts the ERO's request for additional time to prepare the modifications and so directs the ERO to submit the modifications to FAC-012-1 and FAC-013-1 no later than 60 days before the MOD Reliability Standards become effective.

From Order 693 (provided for reference)

782. Although we are not proposing to approve or remand this proposed Reliability Standard (FAC-012-1), the Commission believes that it can be improved. The Commission believes that the process used to determine transfer capabilities should be transparent to the stakeholders, and agrees with International Transmission and MidAmerican that the results of those calculations should not be available for public disclosure but only for qualified entities on a confidential basis. In addition, the process and criteria used to determine transfer capabilities must be consistent with the process and criteria used for other users of the Bulk-Power System. Simply stated, the criteria used to calculate transfer capabilities for use in determining ATC must be identical to those used in planning and operating the system. The Commission directs the ERO to take this into account in its Reliability Standards development process, and to modify the Reliability Standard consistent with Order No. 890 in Docket No. RM05-25-000.

SUBMITTER NOTE – These items were addressed in the ATC-related MOD standards.

790. The Commission does not believe that the regional reliability organization should be able to decide the type of entity to which this Reliability Standard applies. The Commission disagrees with APPA that regional committee processes are essential to determine which planning authorities and reliability coordinators are responsible for determining and distributing each of the specific transfer capability values. Reliability coordinators have a wider-area view of the transmission system than planning authorities, which is important in calculating inter- and intra-regional transfer capabilities. Therefore, the Commission agrees

with MidAmerican that reliability coordinators should calculate transfer capabilities in the operating horizon. The Commission will not address MidAmerican's proposal regarding calculating transfer capabilities in the planning horizon because those Reliability Standards are being considered in Docket No. RM07-3- 000 and are therefore beyond the scope of this proceeding.

794. Accordingly, the Commission approves Reliability Standard FAC-013-1 as mandatory and enforceable, and, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to FAC- 013-1 through the Reliability Standards development process that makes it applicable to reliability coordinators.

SUBMITTER NOTE – Rules for calculating transfer capabilities in the Operating Horizon are addressed within the ATC-related MOD standards. As such, the directive to assign within FAC_013 the responsibilities for this task to the Reliability Coordinator are no longer valid.

From NERC's NOPR Response (provided for reference)

FERC proposes to "direct the ERO to submit a revised FAC-012-1 and a modification to FAC-013-1 to comply with the relevant directives of Order No. 693 and as otherwise necessary to make the requirements of those Reliability Standards consistent with those of the proposed MOD Reliability Standards and the final rule in this proceeding."[1] In order to ensure an accurate understanding of the Commission's expectations, NERC requests clarification of the proposed Commission directive. NERC interprets the proposed directive to mean that these FAC standards: (1) must be changed to address the Planning Horizon to ensure continuity with the ATC-related MOD standards; (2) should not address the Operating Horizon, because the ATC-related MOD standards already address this area; (3) should not delegate oversight and responsibility for this standard to Regional Entities, but rather do so at the ERO level; (4) must not conflict with the ATC-related MOD standards; and (5) must include Violation Risk Factors ("VRF") and Violation Severity Levels ("VSL"). NERC seeks confirmation that this understanding is consistent with the expectations of the Commission regarding this topic.

SUBMITTER NOTE – No direct confirmation from FERC was received; however, this seems to be an appropriate point from which to being modification. .

[1] *Id*. at P 138.

Reliability Functions

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

Reliability and Market Interface Principles

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

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

Related Standards

Standard No.	Explanation

Related SARs

SAR ID	Explanation
Project 2006-07 (“Transfer Capabilities: ATC-TTC-CBM-TRM”)	Completed project that led to the FERC Order and this SAR.

Regional Variances

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	

Attachment 1 — FERC Order 729 Directives and Stakeholder Issues

Source	Language
FERC Order 729	From Order 729: 278. (In the NOPR) The Commission also proposed to not grant NERC's request to withdraw FAC-012-1, nor approve the retirement of FAC-013-1. With respect to these two Reliability Standards, the Commission disagreed with NERC that they are wholly superseded by the MOD Reliability Standards addressed in these proceeding. The Commission noted that, under FAC-012-1, reliability coordinators and planning authorities would be required to document the methodology used to establish inter-regional and intra-regional transfer capabilities and to state whether the methodology is applicable to the planning horizon or the operating horizon. The Commission also noted that, under FAC-013-1, reliability coordinators and planning authorities are required to establish a set of inter-regional and intra-regional transfer capabilities that are consistent with the methodology documented under FAC-012-1, which could require the calculation of transfer capabilities for both the planning horizon and the operating horizon. The Commission posited that these FAC Reliability Standards were necessary because the proposed MOD Reliability Standards provide only for the calculation of available transfer capability and its components, including total transfer capability, in the operating horizon. Thus, the Commission stated, the proposed MOD Reliability Standards do not govern the calculation of transfer capabilities in the planning horizon, i.e., beyond 13 months in the future. 279. In Order No. 693, the Commission approved FAC-013-1, but declined to approve or remand FAC-012-1. The Commission expressed concern that FAC-012-1 merely required the documentation of a transfer capability methodology without providing a framework for that methodology including data inputs and modeling assumptions. The Commission also expressed concern that the criteria used to calculate transfer capabilities for use in determining available transfer capability must be identical to those used in planning and operating the system. The Commission directed the ERO to modify FAC-012-1 to provide a framework for the transfer capability calculation methodology that takes account of the need for consistency in the criteria used to calculate transfer capabilities. 289. Consistent with its NOPR proposal, the Commission finds that NERC has not addressed the requirements of Order No. 693 with regard to the calculation of transfer capabilities in the planning horizon. In Order No. 693 the Commission expressed concern that the criteria used to calculate transfer capabilities for use in determining available transfer capability must be identical to those used in planning and operating the system. As EEI observes, in Order No. 890, the Commission offered, as an example, a possible definition of the operating horizon as the day-ahead and pre-scheduling periods and the planning horizon as anything beyond the operating horizon. However, NERC has already defined the near-term planning horizon as years one through five in sub-requirement R1.2 of TPL-005. The Commission believes that this definition should be consistent throughout the Reliability Standards. 290. The Commission recognizes that the calculation of transfer capabilities in the planning horizon (years one through five) may not be so accurate to support long-term scheduling of the transmission system but we do believe that such forecasts will be useful for long-term planning, in general, by measuring sufficient long-term capacity needed to ensure the reliable operation of the Bulk-Power System. Although regional planning authorities have developed similar efforts in response to Order No. 890, we believe that the requirements imposed by FAC-012 and FAC-013 need not be duplicative of those existing efforts and, by contrast, should be focused on improving the long-term reliability of the Bulk-Power System pursuant to the ERO's Reliability Standards. We believe that these responsibilities would be appropriately assigned to the planning coordinator and not the reliability coordinator. 291. The Commission hereby adopts its NOPR proposal to deny NERC's request to withdraw FAC-012-1 and retire FAC-013-1. Instead, pursuant to section 215(d)(5) of the FPA and section

Source	Language
	39.5(f) of our regulations, the Commission directs the ERO to develop modifications to FAC-012-1 and FAC-013-1 to comply with the relevant directives of Order No. 693 and, as otherwise necessary, to make the requirements of those Reliability Standards consistent with those of the MOD Reliability Standards approved herein as well as this Final Rule. These modifications should also remove redundant provisions for the calculation of transfer capability addressed elsewhere in the MOD Reliability Standards. In making these revisions, the ERO should consider the development of a methodology for calculation of inter-regional and intra-regional transfer capabilities. The Commission accepts the ERO's request for additional time to prepare the modifications and so directs the ERO to submit the modifications to FAC-012-1 and FAC-013-1 no later than 60 days before the MOD Reliability Standards become effective.

Attachment 2 — Global Improvements

Global Improvements

The standard drafting team for each of the projects identified in this plan is expected to review the assigned standards and modify the standards to conform to the latest version of NERC's Reliability Standards Development Procedure, the NERC Standard Drafting Team Guidelines, and the ERO Rules of Procedure as described in this "Global Improvements" section.

Statutory Criteria

In accordance with Section 215 of the Federal Power Act, FERC may approve, by rule or order, a proposed reliability standard or modification to a reliability standard if it determines that "the standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest."

The first three of these criteria can be addressed in large part by the diligent adherence to NERC's *Reliability Standards Development Procedure*, which has been certified by the ANSI as being open, inclusive, balanced, and fair. Users, owners, and operators of the bulk power system that must comply with the standards, as well as the end-users who benefit from a reliable supply of electricity and the public in general, gain some assurance that standards are just, reasonable, and not unduly discriminatory or preferential because the standards are developed through an ANSI-accredited procedure.

The remaining portion of the statutory test is whether the standard is "in the public interest." Implicit in the public-interest test is that a standard is technically sound and ensures a level of reliability that should be reasonably expected by end-users of electricity. Additionally, each standard must be clearly written, so that bulk power system users, owners, and operators are put on notice of the expected behavior. Ultimately, the standards should be defensible in the event of a governmental authority review or court action that may result from enforcing the standard and applying a financial penalty.

The standards must collectively provide a comprehensive and complete set of technically sound requirements that establish an acceptable threshold of performance necessary to ensure the reliability of the bulk power system. "An adequate level of reliability" would argue for both a complete set of standards addressing all aspects of bulk power system design, planning, and operation that materially affect reliability, and for the technical efficacy of each standard. The Commission directed NERC to define the term, "adequate level of reliability" as part of its January 18, 2007 Order on Compliance Filing. Accordingly, NERC's Operating and Planning Committees prepared the definition and the NERC Board approved it at its February 2008 meeting for filing with regulatory authorities. The NERC Standards Committee was then tasked to integrate the definition into the development of future reliability standards.

Quality Objectives

To achieve the goals outlined above, NERC has developed 10 quality objectives for the development of reliability standards. Drafting teams working on assigned projects are charged to ensure their work adheres to the following quality objectives:

1. **Applicability —** Each reliability standard shall clearly identify the functional classes of entities responsible for complying with the reliability standard, with any specific additions or exceptions noted. Such functional classes[2] include: ERO, Regional Entities, reliability coordinators, balancing authorities, transmission operators, transmission owners, generator operators, generator owners, interchange authorities, transmission service providers, market operators, planning coordinators, transmission planners, resource planners, load-serving entities, purchasing-selling entities, and distribution providers. Each reliability standard that does not apply to the entire North American bulk power system shall also identify the geographic applicability of the standard, such as an interconnection, or within a regional entity area. The applicability section of the standard should also include any limitations on the applicability of the standard based on electric facility characteristics, such as a requirement that applies only to the subset of distribution providers that own or operate underfrequency load shedding systems.
2. **Purpose —** Each reliability standard shall have a clear statement of purpose that shall describe how the standard contributes to the reliability of the bulk power system.
3. **Performance Requirements —** Each reliability standard shall state one or more performance requirements, which if achieved by the applicable entities, will provide for a reliable bulk power system, consistent with good utility practices and the public interest. Each requirement is not a "lowest common denominator" compromise, but instead achieves an objective that is the best approach for bulk power system reliability, taking account of the costs and benefits of implementing the proposal.
4. **Measurability —** Each performance requirement shall be stated so as to be objectively measurable by a third party with knowledge or expertise in the area addressed by that requirement. Each performance requirement shall have one or more associated measures used to objectively evaluate compliance with the requirement. If performance results can be practically measured quantitatively, metrics shall be provided within the requirement to indicate satisfactory performance.
5. **Technical Basis in Engineering and Operations —** Each reliability standard shall be based upon sound engineering and operating judgment, analysis, or experience, as determined by expert practitioners in that particular field.
6. **Completeness —** Each reliability standard shall be complete and self-contained. The standards shall not depend on external information to determine the required level of performance.
7. **Consequences for Noncompliance —** Each reliability standard shall make clearly known to the responsible entities the consequences of violating a standard, in combination with guidelines for penalties and sanctions, as well as other ERO and Regional Entity compliance documents.
8. **Clear Language —** Each reliability standard shall be stated using clear and unambiguous language. Responsible entities, using reasonable judgment and in keeping with good utility practices, are able to arrive at a consistent interpretation of the required performance.

[2] These functional classes of entities are derived from NERC's Reliability Functional Model. When a standard identifies a class of entities to which it applies, that class must be defined in the Glossary of Terms Used in Reliability Standards.

9. **Practicality —** Each reliability standard shall establish requirements that can be practically implemented by the assigned responsible entities within the specified effective date and thereafter.

10. **Consistent Terminology —** Each reliability standard, to the extent possible, shall use a set of standard terms and definitions that are approved through the NERC Reliability Standards Development Process.

In addition to these factors, standard drafting teams also contemplate the following factors the Commission uses to approve a proposed reliability standard as outlined in Order No. 672. A standard proposed to be approved:

1. **Must be designed to achieve a specified reliability goal**
   "321. The proposed Reliability Standard must address a reliability concern that falls within the requirements of section 215 of the FPA. That is, it must provide for the reliable operation of bulk power system facilities. It may not extend beyond reliable operation of such facilities or apply to other facilities. Such facilities include all those necessary for operating an interconnected electric energy transmission network, or any portion of that network, including control systems. The proposed Reliability Standard may apply to any design of planned additions or modifications of such facilities that is necessary to provide for reliable operation. It may also apply to cyber security protection."

   "324. The proposed Reliability Standard must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve this goal. Although any person may propose a topic for a Reliability Standard to the ERO, in the ERO's process, the specific proposed Reliability Standard should be developed initially by persons within the electric power industry and community with a high level of technical expertise and be based on sound technical and engineering criteria. It should be based on actual data and lessons learned from past operating incidents, where appropriate. The process for ERO approval of a proposed Reliability Standard should be fair and open to all interested persons."

2. **Must contain a technically sound method to achieve the goal**
   "324. The proposed Reliability Standard must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve this goal.

   Although any person may propose a topic for a Reliability Standard to the ERO, in the ERO's process, the specific proposed Reliability Standard should be developed initially by persons within the electric power industry and community with a high level of technical expertise and be based on sound technical and engineering criteria. It should be based on actual data and lessons learned from past operating incidents, where appropriate. The process for ERO approval of a proposed Reliability Standard should be fair and open to all interested persons."

3. **Must be applicable to users, owners, and operators of the bulk power system, and not others**

"322. The proposed Reliability Standard may impose a requirement on any user, owner, or operator of such facilities, but not on others."

4. **Must be clear and unambiguous as to what is required and who is required to comply**
"325. The proposed Reliability Standard should be clear and unambiguous regarding what is required and who is required to comply. Users, owners, and operators of the Bulk-Power System must know what they are required to do to maintain reliability."

5. **Must include clear and understandable consequences and a range of penalties (monetary and/or non-monetary) for a violation**
"326. The possible consequences, including range of possible penalties, for violating a proposed Reliability Standard should be clear and understandable by those who must comply."

6. **Must identify clear and objective criterion or measure for compliance, so that it can be enforced in a consistent and non-preferential manner**
"327. There should be a clear criterion or measure of whether an entity is in compliance with a proposed Reliability Standard. It should contain or be accompanied by an objective measure of compliance so that it can be enforced and so that enforcement can be applied in a consistent and non-preferential manner."

7. **Should achieve a reliability goal effectively and efficiently - but does not necessarily have to reflect "best practices" without regard to implementation cost**
"328. The proposed Reliability Standard does not necessarily have to reflect the optimal method, or "best practice," for achieving its reliability goal without regard to implementation cost or historical regional infrastructure design. It should however achieve its reliability goal effectively and efficiently."

8. **Cannot be "lowest common denominator," i.e., cannot reflect a compromise that does not adequately protect bulk power system reliability**
"329. The proposed Reliability Standard must not simply reflect a compromise in the ERO's Reliability Standard development process based on the least effective North American practice — the so-called "lowest common denominator"—if such practice does not adequately protect Bulk-Power System reliability. Although the Commission will give due weight to the technical expertise of the ERO, we will not hesitate to remand a proposed Reliability Standard if we are convinced it is not adequate to protect reliability."

9. **Costs to be considered for smaller entities but not at consequence of less than excellence in operating system reliability**
"330. A proposed Reliability Standard may take into account the size of the entity that must comply with the Reliability Standard and the cost to those entities of implementing the proposed Reliability Standard. However, the ERO should not propose a "lowest common denominator" Reliability Standard that would achieve less than excellence in operating system reliability solely to protect against reasonable expenses for supporting this vital national infrastructure. For example, a small owner or operator of the Bulk-

Power System must bear the cost of complying with each Reliability Standard that applies to it."

10. Must be designed to apply throughout North American to the maximum extent achievable with a single reliability standard while not favoring one area or approach
"331. A proposed Reliability Standard should be designed to apply throughout the interconnected North American Bulk-Power System, to the maximum extent this is achievable with a single Reliability Standard. The proposed Reliability Standard should not be based on a single geographic or regional model but should take into account geographic variations in grid characteristics, terrain, weather, and other such factors; it should also take into account regional variations in the organizational and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard."

11. No undue negative effect on competition or restriction of the grid
"332. As directed by section 215 of the FPA, the Commission itself will give special attention to the effect of a proposed Reliability Standard on competition. The ERO should attempt to develop a proposed Reliability Standard that has no undue negative effect on competition. Among other possible considerations, a proposed Reliability Standard should not unreasonably restrict available transmission capability on the Bulk-Power System beyond any restriction necessary for reliability and should not limit use of the Bulk-Power System in an unduly preferential manner. It should not create an undue advantage for one competitor over another."

12. Implementation time
"333. In considering whether a proposed Reliability Standard is just and reasonable, the Commission will consider also the timetable for implementation of the new requirements, including how the proposal balances any urgency in the need to implement it against the reasonableness of the time allowed for those who must comply to develop the necessary procedures, software, facilities, staffing or other relevant capability."

13. Whether the reliability standard process was open and fair
"334. Further, in considering whether a proposed Reliability Standard meets the legal standard of review, we will entertain comments about whether the ERO implemented its Commission-approved Reliability Standard development process for the development of the particular proposed Reliability Standard in a proper manner, especially whether the process was open and fair. However, we caution that we will not be sympathetic to arguments by interested parties that choose, for whatever reason, not to participate in the ERO's Reliability Standard development process if it is conducted in good faith in accordance with the procedures approved by the Commission."

14. Balance with other vital public interests
"335. Finally, we understand that at times development of a proposed Reliability Standard may require that a particular reliability goal must be balanced against other vital public interests, such as environmental, social and other goals. We expect the ERO to

explain any such balancing in its application for approval of a proposed Reliability Standard."

15. Any other relevant factors
"323. In considering whether a proposed Reliability Standard is just and reasonable, we will consider the following general factors, as well as other factors that are appropriate for the particular Reliability Standard proposed."

"337. In applying the legal standard to review of a proposed Reliability Standard, the Commission will consider the general factors above. The ERO should explain in its application for approval of a proposed Reliability Standard how well the proposal meets these factors and explain how the Reliability Standard balances conflicting factors, if any. The Commission may consider any other factors it deems appropriate for determining if the proposed Reliability Standard is just and reasonable, not unduly discriminatory or preferential, and in the public interest. The ERO applicant may, if it chooses, propose other such general factors in its ERO application and may propose additional specific factors for consideration with a particular proposed reliability standard."

Issues Related to the Applicability of a Standard

In Order No. 672, the Commission states that a proposed reliability standard should be clear and unambiguous regarding what is required and who is required to comply. Users, owners, and operators of the bulk power system must know what they are required to do to maintain reliability. Section 215(b) of the FPA requires all "users, owners and operators of the bulk power system" to comply with Commission-approved reliability standards.

The term "users, owners, and operators of the bulk power system" defines the statutory applicability of the reliability standards. NERC's Reliability Functional Model (Functional Model) further refines the set of users, owners, and operators by identifying categories of functions that entities perform so the applicability of each standard can be more clearly defined. Applicability is clear if a standard precisely states the applicability using the functions an entity performs. For example, "Each Generator Operator shall verify the reactive power output capability of each of its generating units" states clear applicability compared with a standard that states "a bulk power system user shall verify the reactive power output capability of each generating unit." The use of the Functional Model in the standards narrows the applicability of the standard to a particular class or classes of bulk power system users, owners, and operators. A standard is more clearly enforceable when it narrows the applicability to a specific class of entities than if the standard simply references a wide range of entities, e.g., all bulk power system users, owners, and operators.

In determining the applicability of each standard and the requirements within a standard, the drafting team should follow the definitions provided in the NERC Glossary of Terms Used in Reliability Standards and should also be guided by the Functional Model.

In addition to applying definitions from the Functional Model, the revised standards must address more specific applicability criteria that identify only those entities and facilities that are material to bulk power system reliability with regard to the particular standard.

The drafting team should review the registration criteria provided in the NERC Statement of Compliance Registry Criteria, which is the criteria for applicability. The registration criteria identify the criteria NERC uses to identify those entities responsible for compliance to the reliability standards. Any deviations from the criteria used in the Statement of Compliance Registry Criteria must be identified in the applicability section of the. It is also important to note that standard drafting teams cannot set the applicability of reliability standards to extend to entities beyond the scope established by the criteria for inclusion on NERC's Compliance Registry. This is expressly prohibited by Commission Order No. 693-A.

The goal is to place obligations on the entities whose performance will impact the reliability of the bulk power system, but to avoid painting the applicability with such a broad brush that entities are obligated even when meeting a requirement will make no material contribution to bulk power system reliability.

Every entity class described in the Functional Model performs functions that are essential to the reliability of the bulk power system. This point is best highlighted with the example that might be the most difficult to understand, the inclusion of distribution providers. Section 215 of the FPA specifically excludes facilities used in the local distribution of electric energy. Nonetheless, some of the NERC standards apply to a class of entities called Distribution Providers. Distribution Providers are covered because, although they own and operate facilities in the local distribution of electric energy, they also perform functions affecting and essential to the reliability of the bulk power system. With regard to these facilities and functions that are material to the reliability of the bulk power system, a distribution provider is a bulk power system user. For example, requirements for distribution providers in the reliability standards apply to the underfrequency load shedding relays that are maintained and operated within the distribution system to protect the reliability of the bulk power system. There are also requirements for distribution providers to provide demand forecast information for the planning of reliable operations of the bulk power system.

A similar line of thinking can apply to every other entity in the Functional Model, including Load-serving Entities and Purchasing-selling Entities, which are users of the bulk power system to the extent they transact business for the use of transmission service or to transfer power across the bulk power system. NERC has specific requirements for these entities based on how these uses may impact the reliability of the bulk power systems. Other functional entities are more obviously bulk power system owners and operators, such as Reliability Coordinators, Transmission Owners and Operators, Generator Owners and Operators, Planning Coordinators, Transmission Planners, and Resource Planners. It is the extent to which these entities provide for a reliable bulk power system or perform functions that materially affect the reliability of the bulk power system that these entities fall under the jurisdiction of Section 215 of the FPA and the reliability standards. The use of the Functional Model simply groups these entities into logical functional areas to enable the standards to more clearly define the applicability.

Issues Related to Regional Entities and Reliability Organizations

Because of the transition from voluntary reliability standards to mandatory reliability standards, confusion has occurred over the distinction between Regional Entities and Regional Reliability Organizations. The regional councils have traditionally been the owners and members of NERC. They have been referred to as Regional Reliability Organizations in the Functional Model and in the reliability standards. In an era of voluntary standards and guides, it was acceptable that a number of the standards included requirements for Regional Reliability Organizations to develop regional criteria, procedures, and plans, and included requirements for entities within the region to follow those requirements. Section 215 of the FPA introduced a new term, called "Regional Entity." Regional Entities have specific delegated authorities, under agreements with NERC, to propose and enforce reliability standards within the region, and to perform other functions in support of the electric reliability organization. The former Regional Reliability Organizations have entered into delegation agreements with NERC to become Regional Entities for this purpose.

Implementation Plan for Standard FAC-013-2 (Planning Transfer Capability)

Prerequisite Approvals

There are no other reliability standards or Standard Authorization Requests (SARs), approved or in progress, that must be implemented before this standard can be implemented.

New or Modified Definitions

The following definitions shall become effective when FAC-013-2 becomes effective:

> **Planning Transfer Capability (PTC):** A forecast of the Transfer Capability between areas that is used in the planning horizon when performing planning analyses.
>
> **Planning Transfer Capability Implementation Document (PTCID):** A document that describes the implementation of a method for calculating Planning Transfer Capability (PTC), and provides information related to a Planning Coordinator's calculation of PTC.

Modified Standards

FAC-012-1 and FAC-013-1 should be retired when FAC-013-2 becomes effective.

Compliance with Standards

Once the standard becomes effective, the responsible entity identified in the applicability section of the standard must comply with the requirements. This includes

- Planning Coordinators

Proposed Effective Date

First day of the first calendar quarter that is six months beyond the date that MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-2 are effective.

Definitions of Terms Used in Standard

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

Planning Transfer Capability (PTC): A forecast of the Transfer Capability between areas that is used in the planning horizon when performing planning analyses.

Planning Transfer Capability Implementation Document (PTCID): A document that describes the implementation of a method for calculating Planning Transfer Capability (PTC), and provides information related to a Planning Coordinator's calculation of PTC.

A. Introduction

1. **Title:** **Planning Transfer Capability**

2. **Number:** FAC-013-2

3. **Purpose:** To ensure that Planning Coordinators calculate Planning Transfer Capabilities using an established method such that those Transfer Capabilities can be used effectively in the reliable planning of the Bulk Electric System (BES).

4. **Applicability**

   4.1. Planning Coordinators

5. **Effective Date:** First day of the first calendar quarter that is six months beyond the date that MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-2 are effective

B. Requirements

R1. Each Planning Coordinator shall prepare and keep current a Planning Transfer Capability Implementation Document (PTCID) that includes, at a minimum, the following information: [*Violation Risk Factor: Medium*] [*Time Horizon: Planning*]

1.1. A list of all Transmission Operators for which the Planning Coordinator determines Planning Transfer Capabilities and for each of these Transmission Operators.

1.1.1. A list of the interfaces for which the Planning Coordinator determines a Planning Transfer Capability.

1.1.2. A detailed explanation of the methods used to calculate Planning Transfer Capabilities, including how those methods are or are not consistent with the methods selected by the Transmission Operator and described in the associated Transmission Service Provider’s Available Transfer Capability Implementation Document (ATCID).

1.1.3. For each case in which the method used to determine a Planning Transfer Capability is not consistent with the method selected by the Transmission Operator and described in the associated Transmission Service Provider’s Available Transfer Capability Implementation Document (ATCID), a justification of the inconsistency.

R2. Each Planning Coordinator shall notify the following entities before implementing a new or revised PTCID: [*Violation Risk Factor: Lower*] [*Time Horizon: Planning*]

2.1. Each Planning Coordinator adjacent to the Planning Coordinator’s planning coordinator area.

2.2. Each Transmission Service Provider within the Planning Coordinator’s planning coordinator area.

2.3. Each Transmission Operator within the Planning Coordinator’s planning coordinator area.

2.4. Each Transmission Planner within the Planning Coordinator’s planning coordinator area.

R3. Each Planning Coordinator shall make available its current PTCID to all of the entities specified in Requirement R2. *[Violation Risk Factor: Lower] [Time Horizon: Planning]*

R4. Each Planning Coordinator shall verify, and if necessary recalculate, PTCs consistent with its PTCID for each season (Spring, Summer, Fall, and Winter) for years two through five at least once each calendar year. [*Violation Risk Factor: Medium*] [*Time Horizon: Planning*]

R5. The Planning Coordinator shall make its PTCs available no later than ten calendar days following their being verified or recalculated to: [*Violation Risk Factor: Lower*] [*Time Horizon: Planning*]

5.1. Each Transmission Planner within the Planning Coordinator's planning coordinator area.

5.2. Any other entities specified in Requirement R2 that have a reliability-related need for such PTCs and make a written request for such PTCs.

C. Measures

M1. Each Planning Coordinator shall have a current, dated PTCID that includes the information specified in Requirement R1.

M2. Each Planning Coordinator shall have evidence (such as dated e-mail or dated phone logs along with its dated new or revised PTCID) that it notified the entities specified in Requirement R2 prior to implementing a new or revised PTCID.

M3. Each Planning Coordinator shall have evidence that it has made its PTCID available to the entities listed in Requirement R2.

M4. Each Planning Coordinator have evidence that it verified, and if necessary recalculated, its PTCs consistent with its PTCID for each winter and summer season for years two through five at least once every three months.

M5. Each Planning Coordinator shall have evidence, such as dated copies of e-mails or dated phone logs, that it made its PTCID available to the entities listed in Requirement R5 no later than ten calendar days following their verification or recalculation.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

The Planning Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Planning Coordinator shall maintain its current, in force ATCID and any prior versions of the PTCID that were in force since the last compliance audit to show compliance with R1.
- The Planning Coordinator shall maintain evidence to show compliance with R2, R3, R4, and R5 for the most recent calendar year plus the current year.
- If a Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

None.

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Planning Coordinator has a PTCID that does not incorporate changes made up to three months ago.	The Planning Coordinator has a PTCID that does not incorporate changes made three months or more but not more than six months ago.	The Planning Coordinator has a PTCID that does not incorporate changes made six months or more but not more than one year ago. **OR** The Planning Coordinator has a PTCID, and it includes some, but not all, of the items described in R1.	The Planning Coordinator has a PTCID that does not incorporate changes made a year or more ago. **OR** The Planning Coordinator has a PTCID, but it includes none of the items described in R1. **OR** The Planning Coordinator does not have a PTCID.
R2	The Planning Coordinator notified one or more of the parties specified in R2 of a new or modified PTCID after, but not more than 30 calendar days after, its implementation.	The Planning Coordinator notified one or more of the parties specified in R2 of a new or modified PTCID more than 30, but not more than 60, calendar days after its implementation.	The Planning Coordinator notified one or more of the parties specified in R2 of a new or modified PTCID more than 60, but not more than 90, calendar days after its implementation.	The Planning Coordinator failed to notify one or more of the parties specified in R2 of a new or modified PTCID more than 90 calendar days following its implementation. **OR** The Planning Coordinator did not notify any of the parties specified in R2 of a new or modified PTCID.
R3	The Planning Coordinator made its PTCID available to some, but not all, of the entities described in R3.	N/A	N/A	The Planning Coordinator made its PTCID available to none of the entities described in R3.
R4.	The Planning Coordinator failed to calculate 5% or less of its PTCs, as specified in the PTCID.	The Planning Coordinator failed to calculate more than 5% up to and including 10% of its PTCs as specified in the PTCID.	The Planning Coordinator failed to calculate more than 10% up to and including 15% of its PTCs, as specified in the PTCID.	The Planning Coordinator failed to calculate 15% or more of its PTCs, as specified in the PTCID.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R5.	The Planning Coordinator made the PTCs available to some, but not all, of the entities described in R5, Part 5.2.	The Planning Coordinator made the PTCs available to none of the entities described in R5, Part 5.2.	The Planning Coordinator made the PTCs available to some, but not all, of the entities described in R5, Part 5.1.	The Planning Coordinator made the PTCs available to none of the entities described in R5, Part 5.1.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
1	08/01/05	1. Changed incorrect use of certain hyphens (-) to "en dash (–)." 2. Lower cased the word "draft" and "drafting team" where appropriate. 3. Changed Anticipated Action #5, page 1, from "30-day" to "Thirty-day." 4. Added or removed "periods."	01/20/05
2	TBD	1. Modified to be consistent with directives contained in FERC Order 729	TBD

Definitions of Terms Used in Standard

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

Planning Transfer Capability (PTC): A forecast of the Transfer Capability between areas that is used in the planning horizon when performing planning analyses.

Planning Transfer Capability Implementation Document (PTCID): A document that describes the implementation of a method for calculating Planning Transfer Capability (PTC), and provides information related to a Planning Coordinator's calculation of PTC.

A. Introduction

1. **Title:** **~~Establish and Communicate~~ Planning Transfer ~~Capabilities~~Capability**

2. **Number:** FAC-013-~~1~~2

3. **Purpose:** To ensure that Planning Coordinators calculate Planning Transfer Capabilities using an established method such that those Transfer Capabilities can be used effectively in the reliable planning ~~and operation~~ of the Bulk Electric System (BES) ~~are determined based on an established methodology or methodologies~~.

4. **Applicability**

   ~~**4.1.**Reliability Coordinator required by its Regional Reliability Organization to establish inter-regional and intra-regional Transfer Capabilities~~

   ~~**4.2.**~~**4.1.** Planning ~~Authority~~ Coordinators~~required by its Regional Reliability Organization to establish inter-regional and intra-regional Transfer Capabilities~~

5. **Effective Date:** First day of the first calendar quarter that is six months beyond the date that MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-2 are effective

B. Requirements

R1. ~~The~~Each ~~Reliability Coordinator and~~ Planning ~~Authority~~ Coordinator shall~~shall each establish a set of inter-regional and intra-regional Transfer Capabilities that is consistent with its current Transfer Capability Methodology.~~ prepare and keep current a Planning Transfer Capability Implementation Document (PTCID) that includes, at a minimum, the following information: [*Violation Risk Factor: Medium*] [*Time Horizon: Planning*]

1.1. A list of all Transmission Operators for which the Planning Coordinator determines Planning Transfer Capabilities and for each of these Transmission Operators.

1.1.1. A list of the interfaces for which the Planning Coordinator determines a Planning Transfer Capability.

1.1.2. A detailed explanation of the methods used to calculate Planning Transfer Capabilities, including how those methods are or are not consistent with the methods selected by the Transmission Operator and described in the associated Transmission Service Provider's Available Transfer Capability Implementation Document (ATCID).

1.1.3. For each case~~s~~ in which the method used to determine a Planning Transfer Capability is not consistent with the method selected by the Transmission Operator and described in the associated Transmission Service Provider's Available Transfer Capability Implementation Document (ATCID), a justification of the inconsistency.

R2. Each Planning Coordinator shall notify the following entities before implementing a new or revised PTCID: [*Violation Risk Factor: Lower*] [*Time Horizon: Planning*]

2.1. Each Planning Coordinator adjacent to the Planning Coordinator's planning coordinator area.

2.2. Each Transmission Service Provider within the Planning Coordinator's planning coordinator area.

2.3. Each Transmission Operator within the Planning Coordinator's planning coordinator area.

2.4. Each Transmission Planner within the Planning Coordinator's planning coordinator area.

R3. Each Planning Coordinator shall make available its current PTCID to all of the entities specified in Requirement R2. *[Violation Risk Factor: Lower] [Time Horizon: Planning]*

R4. Each Planning Coordinator shall verify, and if necessary recalculate, PTCs consistent with its PTCID for each season (Spring, Summer, Fall, and Winter) for years two through five at least once each calendar year. [*Violation Risk Factor: Medium*] [*Time Horizon: Planning*]

R5. The Planning Coordinator shall make its PTCs available no later than ten calendar days following their being verified or recalculated to: [*Violation Risk Factor: Lower*] [*Time Horizon: Planning*]

5.1. Each Transmission Planner within the Planning Coordinator's planning coordinator area.

5.2. Any other entities specified in Requirement R2 ~~The Reliability Coordinator and Planning Authority shall each provide its inter-regional and intra-regional Transfer Capabilities to those entities~~ that have a reliability-related need for such PTCs ~~Transfer Capabilities~~ and make a written request ~~that includes a schedule for delivery of~~for such PTC~~Transfer Capabilities~~s. ~~as follows:~~

- ~~The Reliability Coordinator shall provide its Transfer Capabilities to its associated Regional Reliability Organization(s), to its adjacent Reliability Coordinators, and to the Transmission Operators, Transmission Service Providers and Planning Authorities that work in its Reliability Coordinator Area.~~

- ~~The Planning Authority shall provide its Transfer Capabilities to its associated Reliability Coordinator(s) and Regional Reliability Organization(s), and to the Transmission Planners and Transmission Service Provider(s) that work in its Planning Authority Area.~~

C. Measures

M1. ~~The~~Each ~~Reliability~~ Planning Coordinator ~~and Planning Authority~~ shall ~~each be able to demonstrate that it developed its Transfer Capabilities consistent with its Transfer Capability Methodology~~ha~~s~~ve a current, dated PTCID that includes the information specified in Requirement R1.

M2. ~~The~~Each ~~Reliability~~ Planning Coordinator ~~and Planning Authority shall each have evidence that it provided its Transfer Capabilities in accordance with schedules supplied by the requestors of such Transfer Capabilities.~~ shall have evidence (such as dated e-mail or dated phone logs along with its dated new or revised PTCID) that it notified the entities specified in Requirement R2 prior to implementing a new or revised PTCID.

M3. Each Planning Coordinator shall have evidence that it has made its PTCID available to the entities listed in Requirement R2.

M4. Each Planning Coordinator have evidence that it verified, and if necessary recalculated, its PTCs consistent with its PTCID for each winter and summer season for years two through five at least once every three months.

M5. Each Planning Coordinator shall have evidence, such as dated copies of e-mails or dated phone logs, that it made its PTCID available to the entities listed in Requirement R5 no later than ten calendar days following their verification or recalculation.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

The Planning Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Planning Coordinator shall maintain its current, in force ATCID and any prior versions of the PTCID that were in force since the last compliance audit to show compliance with R1.
- The Planning Coordinator shall maintain evidence to show compliance with R2, R3, R4, and R5 for the most recent calendar year plus the current year.
- If a Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

None.

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Planning Coordinator has a PTCID that does not incorporate changes made up to three months ago.	The Planning Coordinator has a PTCID that does not incorporate changes made three months or more but not more than six months ago.	The Planning Coordinator has a PTCID that does not incorporate changes made six months or more but not more than one year ago. **OR** The Planning Coordinator has a PTCID, and it includes some, but not all, of the items described in R1.	The Planning Coordinator has a PTCID that does not incorporate changes made a year or more ago. **OR** The Planning Coordinator has a PTCID, but it includes none of the items described in R1. **OR** The Planning Coordinator does not have a PTCID.
R2	The Planning Coordinator notified one or more of the parties specified in R2 of a new or modified PTCID after, but not more than 30 calendar days after, its implementation.	The Planning Coordinator notified one or more of the parties specified in R2 of a new or modified PTCID more than 30, but not more than 60, calendar days after its implementation.	The Planning Coordinator notified one or more of the parties specified in R2 of a new or modified PTCID more than 60, but not more than 90, calendar days after its implementation.	The Planning Coordinator failed to notify one or more of the parties specified in R2 of a new or modified PTCID more than 90 calendar days following its implementation. **OR** The Planning Coordinator did not notify any of the parties specified in R2 of a new or modified PTCID.
R3	The Planning Coordinator made its PTCID available to some, but not all, of the entities described in R3.	N/A	N/A	The Planning Coordinator made its PTCID available to none of the entities described in R3.
R4.	The Planning Coordinator failed to calculate 5% or less of its PTCs, as specified in the PTCID.	The Planning Coordinator failed to calculate more than 5% up to and including 10% of its PTCs as specified in the PTCID.	The Planning Coordinator failed to calculate more than 10% up to and including 15% of its PTCs, as specified in the PTCID.	The Planning Coordinator failed to calculate 15% or more of its PTCs, as specified in the PTCID.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R5.	The Planning Coordinator made the PTCs available to some, but not all, of the entities described in R5, Part 5.2.	The Planning Coordinator made the PTCs available to none of the entities described in R5, Part 5.2.	The Planning Coordinator made the PTCs available to some, but not all, of the entities described in R5, Part 5.1.	The Planning Coordinator made the PTCs available to none of the entities described in R5, Part 5.1.

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
1	08/01/05	1. Changed incorrect use of certain hyphens (-) to "en dash (–)." 2. Lower cased the word "draft" and "drafting team" where appropriate. 3. Changed Anticipated Action #5, page 1, from "30-day" to "Thirty-day." 4. Added or removed "periods."	01/20/05
2	TBD	1. Modified to be consistent with directives contained in FERC Order 729	TBD

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Drafting Team Nomination and Standards Authorization Request (SAR) Comment Periods Open Project 2010-10: FAC Order 729

Now available at: http://www.nerc.com/filez/standards/Project2010-10_FAC_Order_729.html

Nominations for Drafting Team (through March 26, 2010)

The Standards Committee is seeking industry experts to serve on the FAC Order 729 Drafting Team (see project background below). The drafting team will work on both SAR and standard development.

If you are interested in serving on this drafting team, please complete this electronic nomination form **by March 26, 2010**.

Comment Period (through April 29, 2010)

The Standards Committee has posted a proposed SAR and draft standard FAC-013-2 — Planning Transfer Capability for a 45-day comment period **ending on April 29, 2010**.

Please use this electronic form to submit comments If you experience any difficulties in using the electronic form, please contact Lauren Koller at Lauren.Koller@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page (see project background below).

Project Background

The purpose of this project is to address FERC directives from Order 729 related to FAC-012-1 and FAC-013-1. The drafting team for Project 2006-07: ATC/TTC/AFC and CBM/TRM Revisions proposed the retirement of FAC-012 and FAC-013, believing that these standards had been effectively superseded four standards developed in the project (MOD-001, MOD-028, MOD-029, and MOD-030). In Order 729, FERC ruled that the standards developed in Project 2006-07 did not completely address the topics covered in FAC-012 and FAC-013 and did not fully address the associated directives from Order 693. Accordingly, FERC denied the portions of the implementation plan that would have retired these standards, and directed NERC to use the standards development process to make changes to the FAC standards and file those changes with FERC no later than 60 days prior to the effective date of the standards approved in Order 729.

Further details are included in the SAR and comment form posted on the project page:
http://www.nerc.com/filez/standards/Project2010-10_FAC_Order_729.html

Standards Development Process

The Reliability Standards Development Procedure contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance,
please contact Shaun Streeter at shaun.streeter@nerc.net or at 609.452.8060.

Individual or group. (15 Responses)
Name (7 Responses)
Organization (7 Responses)
Group Name (8 Responses)
Lead Contact (8 Responses)
Question 1 (14 Responses)
Question 1 Comments (15 Responses)
Question 2 (15 Responses)
Question 2 Comments (15 Responses)
Question 3 (14 Responses)
Question 3 Comments (15 Responses)
Question 4 (2 Responses)
Question 4 Comments (15 Responses)
Question 5 (4 Responses)
Question 5 Comments (15 Responses)
Question 6 (14 Responses)
Question 6 Comments (15 Responses)
Question 7 (14 Responses)
Question 7 Comments (15 Responses)
Question 8 (15 Responses)
Question 8 Comments (15 Responses)
Question 9 (13 Responses)
Question 1 Comments (15 Responses)
Question 10 (14 Responses)
Question 10 Comments (15 Responses)
Question 11 (11 Responses)
Question 11 Comments (15 Responses)
Question 12 (9 Responses)
Question 12 Comments (15 Responses)
Question 13 (6 Responses)
Question 13 Comments (15 Responses)

Group
Northeast Power Coordinating Council
Guy Zito
Yes
Yes
Yes
No
We do not see the need for defining the term Planning Transfer Capability (PTC). The current term Transfer Capability and its definition have been in use for a long period of time. The industry is familiar with this definition, and has an understanding that it is the attainable level of power transfer from one point to another or on a specific transmission path (similarly, TTC is the maximum level of power transfer). The proposed definition is not

compatible with either the definition of Transfer Capability or the definition of Total Transfer Capability in the NERC Glossary, as follows: Transfer Capability: The measure of the ability of interconnected electric systems to move or transfer power in a reliable manner from one area to another over all transmission lines (or paths) between those areas under specified system conditions. The units of transfer capability are in terms of electric power, generally expressed in megawatts (MW). The transfer capability from “Area A” to “Area B” is not generally equal to the transfer capability from “Area B” to “Area A.” Total Transfer Capability: The amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions. If this definition was created to emphasize that this is the term used for planning assessment in the context of this standard, then this could be achieved simply by adding the phrase “in the planning horizon” to the term Transfer Capability. We accept the creation of the term “Transfer Capability Implementation Document". “Planning” should be removed.
No
We do not support the word “Planning” before “Transfer Capabilities” for reasons as indicated in Question 6 preceding. Words such as "Planning Coordinators" and “reliable planning” suffice to put the Transfer Capabilities in the proper time horizon perspective.
Yes
No
(1) We suggest R2 and R3 be combined by “Each Planning Coordinator shall make available its current TCID to all of the following entities, and notify these entities before implementing a new or revised TCID: ... (2) Transmission Planner should be added to Part 2.1. (3) R5 as written may prohibit some entities that have a reliability-related need to obtain the calculated Transfer Capabilities, for example, the Reliability Coordinators. Also, the TCID need-to-know entities in R2 and the TC need-to-know entities in R5 are not consistent. We suggest to make them the same, and include RC in the list.
No
(1) M4 conveys different evidence requirements than what R4 requires. R4 asks for annual verification of each of the four seasons’ Transfer Capabilities. M4 asks for evidence of verification of the Summer and Winter TCs only, but once every 3 months. They are very different from what’s stipulated in the requirement. We suggest M4 be revised to: “Each Planning Coordinator have evidence that it verified, and if necessary recalculated, its TCs consistent with its TCID for each season (Spring, Summer, Fall, and Winter) for years two through five at least once each calendar year. (2) Some Measures may need to be revised depending on the SDT’s response to our comments to Question 9.
No
(1) The retention period for R2 and R3 (or combined as suggested in Question 9) may not provide the evidence needed if there has not been a change to the TCID in the past 24 months. Suggest to change the retention period to be the same as R1. (2) R2: The wording for Lower can be interpreted to mean that the responsible entity did not comply with the requirement even if it notified all entities before implementing a new TCID. We suggest to reword it to: "The Planning Coordinator notified one or more of the parties specified in R2 of a new or modified TCID, but was late by up to 30 calendar days after its implementation." (3) R5: Unlike its R2 counterpart, timing is not factored into the VSLs. We suggest to add a second condition under each VSL as follows: Lower: The Planning Coordinator made the TCs available to one or more of the entities described in R5, Part 5.2, but was late by up to 30 calendar days after the 10 calendar day target. Moderate: The Planning Coordinator made the TCs available to one or more of the entities described in R5, Part 5.2, but was

late more than 30 calendar days after the 10 calendar day target. High: The Planning Coordinator made the TCs available to one or more of the entities described in R5, Part 5.1, but was late by up to 30 calendar days after the 10 calendar day target. Severe: The Planning Coordinator made the TCs available to one or more of the entities described in R5, Part 5.1, but was late more than 30 calendar days after the 10 calendar day target. If the above suggestions are not adopted, then we suggest to add the condition "within 10 calendar days" at the end of each VSL. For example, the Lower VSL will read: "The Planning Coordinator made the TCs available to some, but not all, of the entities described in R5, Part 5.2 within 10 calendar days." (4) Some of the VSLs may need to be revised depending on the SDT's response to our comments to Question 9.
Individual
Ross Kovacs
Georgia Transmission Corporation
Yes
Yes
Yes
No
The definition of Planning Transfer Capability is inconsistent with the definitions of ATC in MOD-001-1 and TTC in MOD-028-1, MOD-029-1, and MOD-030-2. ATC and TTC in the MOD standards are calculated for each ATC Path. A more consistent definition would be "A forecast of the transfer capability for each ATC Path that is used in the Planning Horizon when performing planning analyses". GTC notes that Order 729, paragraph 279 states, "The Commission also expressed concern that the criteria used to calculate transfer capabilities for use in determining available transfer capability must be identical to those used in planning and operating the system. The Commission directed the ERO to modify FAC-012-1 to provide a framework for the transfer capability calculation methodology that takes account of the need for consistency in the criteria used to calculate transfer capabilities."
Yes
Yes
While GTC agrees that the draft standard should merge FAC-012 and FAC-013, the SAR's Detailed Description says "This SAR proposes to retire FAC-012-1, and modify FAC-013-1." How will this inconsistency be explained?
Yes
No
Requirement 4 of the draft standard states, "Each Planning Coordinator shall verify, and if necessary recalculate, PTCs consistent with its PTCID for each season (Spring, Summer, Fall, and Winter) for years two through five at least once each calendar year." However, Measurement 4 states, "Each Planning Coordinator have evidence that it verified, and if

necessary recalculated, its PTCs consistent with its PTCID for each winter and summer season for years two through five at least once every three months." Why is the measurement for each winter and summer season when Requirement 4 specified PTCs for spring, summer, fall, and winter?
No
R1 and R4 are listed as having Medium Violation Risk Factors. R1 is a documentation requirement; R4 requires calculations 13 months before real time. These requirements should have Lower Violation Risk Factors.
No
Requirement 1.1.1 of the draft standard states, "A list of the interfaces for which the Planning Coordinator determines a Planning Transfer Capability". GTC believes this should be ""A list of ATC Paths for which the Planning Coordinator determines a Planning Transfer Capability." This would be consistent with the definitions of ATC in MOD-001-1 and TTC in MOD-028-1, MOD-029-1, and MOD-030-2. ATC and TTC in the MOD standards are calculated for each ATC Path. Order 729, paragraph 291 states, "In making these revisions, the ERO should consider the development of a methodology for calculation of inter-regional and intra-regional transfer capabilities". Will this FERC request be considered? If so, please identify the part of the draft standard that addresses it.
Individual
Kirit Shah
Ameren
No
Draft Standard does not appear to provide details on the data input and modeling assumptions from Order 693.
Yes
No
We believe that, in R4, PC should coordinate verification of PTC with TP(within PC's planning coordinator area).
No
What is the need for PTC? We believe that well established NERC terms like ATC, TTC, FCITC should be used. The proposed definition of PTC is not consistent these terms. Furter, we have several questions with regard to PTC : Is PTC simultaneous or non-simultaneous? How is PTC will be used? Is PC going to decide how it would be used?
No
Please see our comments to question 6.
Yes
No
Please see our response to question 1.
No
Measure 4 is not consistent with the requirement. The requirement requires recalculation once a calendar year and the measure attempts to require recalculation once a quarter. Do we need spring and fall PTC (R4) when the vales more appropriate for planning would be

summer and winter as included in M4.
(1) In R5, PTC should be available to all the entities in R2 without being asked. TOP will be more interested in changes in PTC than changes in PTCID. (2) It is unclesr if PTC to be calculated between TOP areas, or from BA to BA, region to region, or sub-region to sub-refion? The document should require PC to work with TP and TOP to identify necessary interfaces to calculate transfer capabilitoes for Planning horizon. (3) PTC should be referred to as an acronym in R1.1 when it is used first time as the acronym was used then in R4.
Individual
Dan Rochester
Independent Electricity System Operator
Yes
Yes
Yes
No
We do not see the need for defining the term Planning Transfer Capability (PTC). The current term Transfer Capability and its definition have been adopted for a long period of time. The industry is familiar with this definition, and have a deep and unambiguous understanding that in general term, it is the attainable level of power transfer from one point to another or on a specific transmission path (similarly, TTC is the maximum level of power transfer). We view the proposed definition as redundant since it is similar to the definitions of Transfer Capability and Total Transfer Capability already in the NERC Glossary, viz.: Transfer Capability: The measure of the ability of interconnected electric systems to move or transfer power in a reliable manner from one area to another over all transmission lines (or paths) between those areas under specified system conditions. The units of transfer capability are in terms of electric power, generally expressed in megawatts (MW). The transfer capability from “Area A” to “Area B” is not generally equal to the transfer capability from “Area B” to “Area A.” Total Transfer Capability: The amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions. If the reason to create this definition is to make a distinction that this is the term used for planning assessment in the context of this standard, then we believe that this can be achieved simply by adding the phrase “in the planning horizon” to the term Transfer Capability. We do not have a difficulty with the creation of the term “Transfer Capability Implementation Document for so long as the word “Planning” is removed.
No
We do not support the word “Planning” before “Transfer Capabilities” for reasons as indicated under Q6, above. Words such as “Planning Coordinators and “reliable planning” already suffice to put the Transfer Capabilities in the proper time horizon perspective.
Yes

No
(1) We suggest R2 and R3 be combined by "Each Planning Coordinator shall make available its current PTCID to all of the following entities, and notify these entities before implementing a new or revised TCID: ……. (2) We believe the Transmission Planner should be added to Part 2.1. (3) R5 as written may preclude some entities that have a reliability-related need to obtain the calculated Transfer Capabilities from receiving them, for example, the Reliability Coordinators. Also, the TCID need-to-now entities in R2 and the TC need-to-know entities in R5 are not consistent. We suggest to make them the same, with consideration of including the RCs in the list.
No
(1) M4 conveys different evidence requirements than what R4 requires. R4 asks for annual verification of each of the four seasons' Transfer Capabilities. M4 asks for evidence of verification of the Summer and Winter TCs only, but for once every 3 months. They are very different that what's stipulated in the requirement. We suggest M4 be revised to: "Each Planning Coordinator shall have evidence that it verified, and if necessary recalculated, its TCs consistent with its TCID for each season (Spring, Summer, Fall, and Winter) for years two through five at least once each calendar year. (2) Some Measure may need to be revised depending on the SDT's response to our comments under Q9.
No
(1) The retention period for R2 and R3 (or to be combined as we suggest) may not provide the evidence needed if there has not been a change to the TCID in the past 24 months. Suggest to change the retention period to be the same as R1. (2) R2: For the Lower VSL we suggest the following alternative wording to avoid any possible misinterpretation: "The Planning Coordinator notified one or more of the parties specified in R2 of a new or modified PTCID, but was late by up to 30 calendar days after its implementation. (3) R5: Unlike its R2 counterpart, timing is not factored into the VSLs. We suggest to add a second condition under each VSL as follows: Lower: The Planning Coordinator made the TCs available to one or more of the entities described in R5, Part 5.2, but was late by up to 30 calendar days after the 10 calendar day target. Moderate: The Planning Coordinator made the TCs available to one or more of the entities described in R5, Part 5.2, but was late more than 30 calendar days after the 10 calendar day target. High: The Planning Coordinator made the TCs available to one or more of the entities described in R5, Part 5.1, but was late by up to 30 calendar days after the 10 calendar day target. Moderate: The Planning Coordinator made the TCs available to one or more of the entities described in R5, Part 5.1, but was late more than 30 calendar days after the 10 calendar day target. If the above suggestions are not adopted, then we suggest to add the condition "within 10 calendar days" at the end of each of the VSL. For example, the Lower VSL will read: "The Planning Coordinator made the TCs available to some, but not all, of the entities described in R5, Part 5.2 within 10 calendar days." (4) Some of the VSLs may need to be revised depending on the SDT's response to our comments under Q9.
Individual
Kasia Mihalchuk
Manitoba Hydro
No
Manitoba Hydro does not believe FERC should mandate changes to international standards. Order 729 required elimination of redundancies between FAC-012 and the new MOD standards (1, 28-30). This can easily be accomplished by removing reference to the Reliability Coordinator in R1 through R4. Order 693 required a more detailed framework of

the data inputs and modeling assumptions. This could be added as an additional requirement R1.4 in the existing FAC-012 standard. There is no strong reliability need to have a consistent methodology between the operating and planning horizons. However, there should be a need to ensure the methodologies used by adjacent Planning Coordinators for the same interface are consistent. Requirement R4 is a step in this direction in the existing standard but is completely missing in the revised standard. The proposed changes make the Transfer Capability calculations in the 2-5 year period too close to a full operational study. This is not consistent with the direction given by Order 729 and 693 where the numbers are not intended to grant transmission service.
No
The SAR requires the PC to complete many detailed studies and verifications. This is unnecessary work in determining planning horizon PTCs. The SAR assumes TOs have a large interest in Planning Horizon PTCs. This is not always the case.
Yes
The SAR requires that the PTCID line up with the ATC methodology in the operating horizon (the ATCID). This implies full blown operating studies in the planning horizon (spring. Summer, fall winter years 2 to 5). The accuracy and uncertainty of planning horizon PTCs mean these PTCs will not necessarily allow for transmission service. So why is it necessary for PCs to do the detailed work required to ensure the PTCID line up with the ATC methodology in the operating horizon (the ATCID)?
No
The PTC definition should refer to 'interfaces', not 'areas'. It should align with R1.1.1 which refers to interfaces. The PTC is a transfer capability not a forecast of a transfer capability. Proposed PTC definition: Planning Transfer Capability: The measure of the ability of interconnected electric systems to move or transfer power in a reliable manner from one area to another over all transmission lines (or paths) between those areas under specified system conditions in the planning horizon of one year or longer.The group of lines or paths between adjacent areas comprise an interface. Why is it necessary to have a new definition instead of using the definition of Transfer Capability in the NERC Glossary: The measure of the ability of interconnected electric systems to move or transfer power in a reliable manner from one area to another over all transmission lines (or paths) between those areas under specified system conditions. The units of transfer capability are in terms of electric power, generally expressed in megawatts (MW). The transfer capability from "Area A" to "Area B" is not generally equal to the transfer capability from "Area B" to "Area A." The standard could just refer to "Transfer Capability in the planning horizon. Planning horizon should be defined. The PTCID definition is unnecessarily wordy. Also, the PTCID should describe a method not an 'implementation of a method'. Proposed PTCID definition: PTCID: A document that describes the method for calculating PTC.
No
The proposed purpose is unclear. What does 'used effectively in the reliable planning of the Bulk Electric System (BES)' mean? The purpose statement should simply be: To ensure that Planning Coordinators calculate Planning Transfer Capabilities using an established method. Also, if FAC-012-1 and FAC-013-1 are combined, the purpose should include a statement such as "and distribute the PTCs to the entities that have a reliability related requirement for them".
No
Manitoba Hydro strongly suggests that the Standard Drafting Team revert back to FAC-012. With some minor modifications to the current FAC-012, a clear and adequate standard

could be established. By dropping the reference to the RC in R1 & R4 & M1 & M4 & D, R2 and M2 the current FAC-012 would be applicable only to the PA (not the PA and the RC). Requirement R1 in FAC-012 lists some important items that should be included in a transfer capability methodology. These items are not included in the proposed FAC-013-2 standard. There is nothing in the proposed FAC-013-2 standard that makes it superior to the current FAC-012 standard.
No
In order 729 point 279 the following is stated: 'The Commission expressed concern the FAC-012-1 merely required the documentation of a transfer capability methodology without providing a framework for that methodology including data inputs and modeling assumptions.' Where in the draft standard is it required that the PTCID provide data inputs and modeling assumptions?
No
M4: This measure should only require the PC have evidence that it verified , and if necessary recalculated, its PTCs consistent with its PTCID for each winter and summer season for years two through five at least once a year. In R4 is it stated '…at least once each calendar year.'. M5: PTCID should be changed to PTCs. Also, since the PC's PTCs are in the Planning Horizon, there is no need to make them available within a time frame as short as ten calendar days. One month would be a more appropriate time frame.
No
The Violation Risk Factors should all be Lower. The Time Horizons are all Planning and as such violating any of the Requirements in this proposed standard will not result in anything more than a low level of risk. Violation Severity Levels: R1: The VSLs refer to times of three months/six months/not more than one year/a year or more whereas Requirement R1 does not refer to any time periods. R2: The VSLs refer to times of 30 calendar days/31-60 calendar days/61-90 calendar days/more than 90 calendar days whereas Requirement R2 does not refer to any time periods. R3: The VSLs are not properly allocated for a binary VSL Requirement. R5: The VSLs do not mention any time periods whereas Requirement R5 states '…no later than ten calendar days…'.
No
Manitoba Hydro strongly suggests that the Standard Drafting Team refer back to FAC-012. With some minor modifications to the current FAC-012, a clear and adequate standard could be established. By dropping 4.1, the reference to the RC in R1 & R4 & M1 & M4 & D, R2 and M2 the current FAC-012 would be applicable only to the PA (not the PA and the RC). Requirement R1 in FAC-012 lists some important items that should be included in a transfer capability methodology. These items are not included in the proposed FAC-013-2 standard. There is nothing in the proposed FAC-013-2 standard that makes it superior to the current FAC-012 standard. Referring to the proposed FAC-013-2 Standard, R4 requires the PC to complete many detailed studies and verifications. This is unnecessary work in determining planning horizon PTCs. R4 should be changed to 'Each Planning Coordinator shall verify, and if necessary recalculate, PTCs consistent with its PTCID for the Summer and Winter seasons for years two and five at least once each calendar year.' Spring and Fall models are not currently created in the Planning Horizon. Requiring the PC to model and analyze Spring and Fall models in the Planning Horizon seems to be market driven, rather than reliability driven. There are is no requirement that the PCs on either side of an 'interface' coordinate when determining PTCs for the 'interface'. The Effective Date cannot be dependent on another standards' effective date (ie. cannot be dependent are the date that MOD-001-1, MOD-028-1, MOD-029-1 and MOD-030-2 are effective).
Individual

Jon Kapitz
Xcel Energy
Yes
The SAR appears to fully address the directives; however, it is not clear if the draft standard provides sufficient details on the data inputs and modeling assumptions as directed from originally in Order 693.
Yes
Yes
We agree, however the mapping of entities to Planning Coordinators is an ongoing gap in the registration process. Many entities (primarily non-RTO) are unable to point to who their PC is and similarly, entities who are PCs self define the entities they cover. To our knowledge, there is no source to identify the mapping of these relationships. Therefore, prior to implementation of standards that propose very prescriptive requirements on the PC and their interactions with subordinate entities it is important that the relationships are clearly established as a point of reference.
Business Practice
Business Practice: WECC Planning Coordination Committee (PCC) Handbook Comments: Entities within WECC may be using this to establish path ratings
No
No
There is no need to create the term Planning Transfer Capability (PTC). Transfer Capability is a well understood long standing NERC defined term and should be used in its place. Furthermore, the proposed definition is not consistent with the Transfer Capability or Total Transfer Capability definitions.
No
Planning Transfer Capability should be replaced with Transfer Capabilities. As an option, the purpose statement could refer to the Transfer Capabilities in the planning horizon.
Yes
No
The draft standard does not provide much detail around the data inputs and modeling assumptions requirements that Order 693 directed.
No
We believe it is premature to establish and review measures until the refinement of requirements is closer to completion
Yes
It is not clear why the document focuses on Transmission Operators and not the traditional way in calculating transfer capabilities such as from BA to BA, region to region, sub-region to sub-region. The document should simply require the PC to identify what necessary interfaces it will calculate transfer capabilities on.
Individual
Darcy O'Connell
California ISO

Yes
Yes
Yes
Yes
Yes
Yes
No
In support of the SRC comments related to question 9, we suggest the SDT to review both the draft FAC-013-2 and the approved MOD Standards (i.e., MOD-028 or MOD-029) to ascertain that FERC’s concerns regarding data input and modeling assumptions are fully addressed. We also support the SRC comment to include the RC in R5.
No
M4 conveys different evidence requirements compared to what R4 requires. We suggest that R4 and M4 provide some flexibility to the Planning Coordinator to study and verify the conditions that are appropriate for the study area, rather than to require for all four seasons. For example, a peak and off-peak study in R4 may be appropriate for a study area. Similar flexibility in the language should be included in M4. Suggested wording for M4 would be: "Each Planning Coordinator have evidence that it verified, and if necessary recalculated, its PTCs consistent with its PTCID for relevant study scenarios as appropriate for the study area."
No
We request consideration be given to extend the “no later than 10 calendar days” time allowed in R5 and the VSLs for R5 to "no later than 15 calendar days." We suggest the following for R5 VSLs: Lower VSL: The Planning Coordinator made the PTCs available to one or more of the entities described in R5, Part 5.2, after 15 calendar days. Moderate VSL: The Planning Coordinator made the PTCs available to none of the entities described in R5, Part 5.2, within 15 calendar days. High VSL: The Planning Coordinator made the PTCs available to one or more of the entities described in R5, Part 5.1, after 15 calendar days. Severe VSL: The Planning Coordinator made the PTCs available to none of the entities described in R5, Part 5.1 within 15 calendar days.
No
We suggest that R4 and M4 provide some flexibility to the Planning Coordinator to evaluate the conditions that are appropriate for the study area, rather than to require all four seasons be evaluated. For example, a peak and off-peak study in R4 may be appropriate for a study area. For R4, where it specifies for years two through five, we request that the SDT consider years two and five, similar to the proposed Requirement 2.1.1 in Draft 5 of the TPL-001-1 Standard that is under development in NERC Project 2006-02. For R5, we ask the SDT to give consideration to extending the timeframe allowed beyond 10 calendar days to 15 calendar days.

Group
Southern Company Transmission
Stephen Mizelle
Yes
Southern believes the description of the SAR fully addresses the applicable directives from FERC Order 693 and FERC Order 729. Southern interprets the main directives from these respective orders as: 1) modify FAC-12-1 and FAC-13-1 to address calculation and communication of Transfer Capabilities for the timeframe beyond 13 months, 2) modifications to these FAC standards should not address the timeframe from 1 hour through 13 months, 3) modify FAC-13 to be applicable to the Planning Coordinator only and not the Reliability Coordinator, and 4) remove redundant provisions for the calculation of Transfer Capabilities addressed elsewhere in the MOD Reliability Standards. Southern agrees with NERC's interpretation that the revised FAC standards must not conflict with the ATC-related MOD standards as long as NERC's interpretation is that the revised FAC standards do not prescribe additional requirements for the calculation of Transfer Capabilities in the operating horizon. However, Southern would disagree if NERC's interpretation is that the methodologies described in the MOD Reliability Standards (MOD-28-1, MOD-29-1, and MOD-30-2) must be utilized to calculate Transfer Capabilities for the timeframe beyond 13 months. Southern does not believe that there are existing standards that provide the framework for calculation of Transfer Capabilities beyond 13 months.
Yes
Yes
No
No
In general, Southern agrees with the proposed definitions of PTC and PTCID; however, Southern would like to propose a revision to the definition of PTC to capture that PTC is the forecast of Transfer Capabilities beyond the 13 month timeframe. The calculations of Transfer Capabilities within the timeframes from 1 hour up to 13 months have been adequately covered by the MOD Reliability Standards approved within FERC's Order 729. Additionally, the term "Planning Horizon" is not a term currently defined in the NERC Glossary. Although FERC implied in Order 729 that the planning horizon is years one through five, Southern recommends that NERC either define the term Planning Horizon or rephrase the definition of PTC to capture the applicable timeframe as specified in FERC Order 729 without referencing the term Planning Horizon.
Yes
Southern agrees with NERC's proposed purpose statement in that Transfer Capabilities should be calculated using an established method and used effectively for the reliable planning of the Bulk Electric System. However, Southern does not believe that NERC's proposed FAC-13-2 addresses this purpose statement. Southern does not believe there are currently any established methods for which Transfer Capabilities are calculated beyond the 13 month timeframe. The existing MOD Reliability Standards (MOD-28-1, MOD-29-1, and MOD-30-2) provide for the calculation of Transfer Capabilities in the operating horizon only (i.e. up to 13 months). FERC's directive in Order 729 was to develop modifications to FAC-12-1 and FAC-13-1 to comply with the relevant directives of Order No. 693, in which, NERC was directed to modify FAC-12-1 to provide a framework for calculating transfer capability.

Southern believes NERC has fully addressed this framework in regards to the operating horizon with the MOD Reliability Standards approved within FERC Order 729. As such, Southern recommends that existing reliability standards (i.e. FAC-12-1) be modified or new reliability standards be created to provide a framework for the calculation of Transfer Capabilities beyond 13 months.
No
Southern does not support merging FAC-12 and FAC-13 unless a single method for calculating Transfer Capabilities beyond 13 months is approved. FAC-13-1 is a FERC approved standard that requires either the reliability coordinator or the planning authority to calculate transfer capabilities based on an established methodology and provide those transfer capabilities to its transmission operators, transmission service providers and planning authorities within the reliability coordinator's area. In FERC's Order 729, the commission stated that the responsibilities of FAC-12 and FAC-13 would be appropriately assigned to the Planning Coordinator and not the reliability coordinator. FAC-13 is simply a standard by which Transfer Capabilities calculated by a Planning Coordinator should be communicated to the Transmission Operator and Transmission Service Provider. FAC-13 does not prescribe how to calculate these Transfer Capabilities. As previously stated, Southern does not believe that there are established methodologies that provide the framework for calculating Transfer Capabilities beyond 13 months. Southern recommends that either FAC-12 be modified to provide the framework for a single methodology used for calculating Transfer Capabilities beyond 13 months or additional standards be created to provide such frameworks similar to those prescribed in the MOD Reliability Standards (MOD-28-1, MOD-29-1, and MOD-30-2). Additionally, Southern would not support the modification of MOD-28-1, MOD-29-1, or MOD-30-2 in order to provide this framework beyond 13 months.
No
In FERC Order 693, the commission directed NERC to modify FAC-12 to, at a minimum, provide a framework for the transfer capability calculation methodology, including data inputs and modeling assumptions. Southern believes that this directive has been fully addressed for the timeframe of 1 hour through 13 months with the MOD Reliability Standards approved within FERC Order 729. The commission stated in FERC Order 729 that calculation of transfer capabilities for the planning horizon (years one through five) had not been addressed by the MOD Reliability Standards and gave additional directives that FAC-12 and FAC-13 be modified to comply with the original directives of FERC Order 693. The primary requirements of the draft standard require the Planning Coordinator to: 1) define the interfaces in which Transfer Capabilities are calculated, 2) explain why the method used to calculate these Transfer Capabilities differ from the method selected by the Transmission Operator in Transmission Service Provider's ATCID, and 3) share the calculated Transfer Capabilities with specified entities. However, the draft standard does not provide the framework for how the Transfer Capabilities should be calculated; and, as previously stated, Southern does not believe that there are established methodologies that provide the framework for calculating Transfer Capabilities beyond 13 months. Therefore, Southern contends that the draft standard does not meet the directive of providing the framework for calculating Transfer Capabilities beyond 13 months.
No
Southern disagrees with measure M4 in that verification, or possible recalculation of PTCs, should be performed any more frequent than once a year. Southern does not believe that there is a reliability need to calculate PTCs on a quarterly basis for PTCs to be utilized beyond the 13 month horizon. Additionally, Southern does not believe there is a reliability need to calculate seasonal PTCs; and therefore, disagrees that each winter and summer season for years two through five should be verified, or recalculated at least once every

three months.
Yes
No
Yes
Southern disagrees with requirement R1.1.2 in that a Planning Coordinator should have to provide a detailed explanation as to why the methods used to calculate PTCs are or are not different from those methods selected by the Transmission Operator as described in the Transmission Service Providers ATCID. The methods selected by the Transmission Operator in the ATCID do not provide the framework to calculate Transfer Capabilities beyond 13 months. Additionally, Southern disagrees with requirement R.1.1.3 to provide a justification as to why a method identified in a Planning Coordinator's PTCID is inconsistent with the Transmission Service Provider's ATCID. The existing, FERC approved MOD-001-1 allows for a path of which ATC is calculated to utilize different methodologies for different timeframes. For example, a Transmission Service Provider could select MOD-28-1 (Area Interchange) to utilize when calculating Transfer Capabilities for use in Hourly ATC calculations and select MOD-29-1 (Rated System Path) to utilize when calculating Transfer Capabilities for use in Monthly ATC calculations without requiring any justification for why the Transmission Service Provider chose to select different methods for the different timeframes. As such, Southern does not agree with any requirement to justify why a Planning Coordinator chose a different method for calculating Transfer Capabilities beyond 13 months. Southern disagrees with requirement R4 in that the calculation of seasonal transfer capabilities should be calculated for years two through five. Southern does not believe that there is a reliability need for Planning Coordinators to calculate seasonal PTCs. Each Planning Coordinator determines the most critical system condition for their respective area and performs reliability evaluations on these critical system conditions when creating their reliability expansion plan. Therefore, each Planning Coordinator should not be required to calculate seasonal PTCs for a timeframes that haven't been defined as a critical system condition for their area. Southern recommends that yearly Transfer Capabilities should be the only Transfer Capabilities calculated beyond 13 months through five years and that these Transfer Capabilities be calculated no more than annually.
Group
Midwest ISO Stakeholder Standards Collaborators
Jason L. Marshall
No
The SAR appears to fully address the directives; however, it is not clear if the draft standard provides sufficient details on the data inputs and modeling assumptions as directed in Order 693.
Yes
No
The drafting team should review if there are any requirements needed to compel registered entities such as TP, TO, TOP, GO, GOP, and BA to provide any data that the PC needs to complete its function. If the data is already required through other requirements in other standards, then additional requirements are not needed.
No

There is no need to create the term Planning Transfer Capability (PTC). Transfer Capability is a well understood long standing NERC defined term and should be used in its place. Furthermore, the proposed definition is not consistent with the Transfer Capability or Total Transfer Capability definitions.
No
Planning Transfer Capabilities should be replaced with Transfer Capabilities. As an option, the purpose statement could refer to the Transfer Capabilities in the planning horizon.
Yes
No
The draft standard does not provide much detail around the data inputs and modeling assumptions requirements that Order 693 directed.
No
Measure 4 is not consistent with the requirement. The requirement requires recalculation once a calendar year and the measure attempts to require recalculation once a quarter.
Yes
It is not clear why the document focuses on Transmission Operators and not the traditional way in calculating transfer capabilities such as from BA to BA, region to region, sub-region to sub-region. The document should simply require the PC to identify what necessary interfaces it will calculate transfer capabilities on. R2 and R3 should be combined into a single requirement. R2 in essence requires pre-notification of coming changes to the PTCID but there is no need to specify what the changes are. Then R3 requires notification again to the same entities with an actual copy of the changes. R2 as written is an administrative requirement that provides no reliability benefit. Resource Planners should receive copies of the Transfer Capabilities in R5 as well. They need to know their import capabilities in order to determine if they have access to sufficient generation to cover their load.
Group
Bonneville Power Administration
Denise Koehn
No
BPA would like clarification regarding the relationship between FAC-010-2 and FAC-014-2 and the proposed FAC-013-2, specifically regarding the difference between establishing a System Operating Limit in the Planning Horizon and establishing Planning Transfer Capabilities.
No
The definition of Planning Transfer Capability is vague. It is unclear if Planning Transfer Capability is meant to be different than Total Transfer Capability in the Planning Horizon. Is Planning Transfer Capability the same as Total Transfer Capability in the Planning Horizon? If not, how are they different? How does PTC relate to the requirements in FAC-010-2 regarding determination of the System Operating Limit for the Planning Horizon? BPA disagrees with the proposed definition of PTC and does not see the need for this new term.
No

It is unclear what the difference is between the purpose statement of the proposed FAC-013-2 and the purpose statements of FAC-010-2 and FAC-014-2. The purpose statements seem to be identical. BPA asks for clarification regarding the need for this proposed standard. For reference the purpose statement of FAC-010-2 reads as follows: "To ensure that System Operating Limits (SOLs) used in the reliable planning of the Bulk Electric System (BES) are determined based on an established methodology or methodologies." The purpose statement of FAC-014-2 reads as follows: "To ensure that System Operation Limits (SOLs) used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies."
No
BPA proposes to retire FAC-012 and FAC-013 and instead modify FAC-010-2, and FAC-014-2 to respond to FERC's directives in Order 693 and Order 729. This will avoid the appearance of duplication and provide consistency between these standards.
No
Comment #1: R4 does not line up with M4. R4 requires PTCs for spring, summer, fall, and winter while M4 only requires PTCs for each winter and summer. Also R4 requires PTCs to be verified and recalculated, if necessary, at least once each calendar year while M4 requires verification and recalculation of PTCs, if necessary, every three months. These are inconsistent. o BPA proposes the following modification to R4: "Each Planning Coordinator shall verify, and if necessary, recalculate PTCs consistent with its PTCID at least once a year for at least the most limiting season (spring, summer, fall, or winter) for years two through five." o BPA proposes the following language for M4: "Each Planning Coordinator have evidence that it verified, and if necessary, recalculated, its PTCs consistent with its PTCID at least once a year for the most limiting season (spring, summer, fall, or winter) for years two through five." Comment #2: R5 does not line up with M5. R5 requires the Planning Coordinator to make available PTC values to the entities listed, while M4 requires Planning Coordinators to make available the PTCID to those entities. The VSL indicates the Planning Coordinator makes available the PTCs. Is this correct?
No
Comment #1: The 1.4 Data Retention requirement mandates that the Planning Coordinator maintain its current ATCID. Was the intent for the Planning Coordinator to maintain its current PTCID? Comment #2: The risk to reliability from not complying with this standard is very low as it addresses the Planning horizon. A severe Violation Severity Level is too high for these standards. Comment #3: BPA proposes the following changes for the VSL's for R1: o Lower VSL: The Planning Coordinator has a PTCID that does not incorporate changes made up to six months ago. o The wording used for High VSL should replace the wording for Moderate VSL. o The wording used for Severe VSL should replace the wording for High VSL. Comment #4: BPA proposes the following changes to R2: o Lower VSL: The Planning Coordinator failed to notify one or more parties specified in R2 of a new or modified PTCID after, but no more than 45 days after its implementation. o Moderate VSL: The Planning Coordinator failed to notify one or more parties specified in R2 of a new or modified PTCID more than 45, but no more than 90 calendar days after its implementation. o High VSL: The Planning Coordinator failed to notify one or more of the parties specified in R2 of a new or modified PTCID more than 90 calendar days following its implementation. Comment #5: BPA proposes that there should be only one VSL for R3 and it should read as follows: o High VSL: The Planning Coordinator failed to make its PTCID available to one of more of the entities described in R3. Comment #6: BPA proposes that there should be only one VSL for R5 and it should read as follows: o High VSL: The Planning Coordinator failed to make the PTCs available to one or more of the entities described in R5, Part 5.2.

Individual
Greg Rowland
Duke Energy
Yes
However, we don’t believe that it’s possible to maintain a strict adherence to the FERC directive that the methodology and criteria used to determine Planning Transfer Capability (PTC) in the planning timeframe be identical to, or even consistent with, those used in determining ATC in the operating timeframe. The methodologies and criteria need to be different in some instances because the objectives are different. In the operating timeframe, realistic assumptions and data reflecting the expected operating conditions of the system must be used for determining ATC. In the planning timeframe, different assumptions for operating conditions and contingencies are used to determine how robust the system is in response to more extreme events. For example, a study might examine the impacts of significantly reduced generation from unscrubbed coal plants. Furthermore, analyses in the planning timeframe may use different tools (and thus treat inputs differently) such as PSSE, versus an ATC tool such as MUST.
No
The granularity of the proposed standards action is too great. And there is too much linkage between PTCID and ATCID that is not achievable, or even desirable, since the ATCID addresses transfer capability to support reliable operation of the system, while PTCID addresses planning of the system for reliability under a potentially wide range of future conditions.
Yes
none
No
Yes
No
The Purpose should be reworded to clearly state that the objective of this standard is not to simply determine transfer capabilities in the planning timeframe, but to assess the future reliability of the system. Suggested rewording: “To ensure that Planning Coordinators use an established methodology to assess whether sufficient transmission system capacity is available to support reliable operation of the Bulk Power System in the planning horizon.”
Yes
Yes
No
Requirement R4 is much too prescriptive and we propose changes to it in our response to Question # 13 below. Measure M4 should be revised to match the revised requirement. Likewise Requirement R5 has far too tight a timeframe to communicate verified or recalculated transfer capabilities. Since these transfer capabilities are years in the future, 45 days should be allowed to communicate them instead of 10 days.
No
Requirement R1 should be a Lower VRF, since it’s a documentation requirement. Also, VSLs

should be revised consistent with proposed changes to the requirements.
No
Yes
• Delete Requirements R2.2 and R2.3 because TSPs and TOPs really have no need of the PTCID. • Requirement R4 specifies a frequency that is overly prescriptive/granular and unnecessary for assessments in the planning timeframe. Suggested rewording: "Consistent with its PTCID, each Planning Coordinator shall assess PTCs in the near-term planning horizon and the long-term planning horizon at least once every two years." • Change the time in Requirement R5 from 10 days to 45 days, since this is a planning timeframe requirement. • Reword Requirement R5.2 to indicate that any other registered entities (not just those specified in R2) that have a reliability-related need can make a written request and receive the PTCs. • Add a new Requirement R5.3 as follows: "Each Planning Coordinator adjacent to the Planning Coordinator's planning coordinator area." • Under Data Retention, there is a typo in the second bullet: ATCID should be PTCID.
Group
PJM Interconnection
Patrick Brown
Yes
Yes
Yes
Business Practice
PJM does not believe that a transfer capability methodology is the only valid option for the planning horizon. PJM's current, FERC approved, integrated queue study process (part of the PJM Regional Transmission Expansion Planning Process) requires that PJM study the base system and resolve any reliability criteria violations by implementing system upgrades. PJM then studies the integrated queue in the order in which the queued projects were received and resolves any reliability criteria violations by implementing system upgrades. This method ensures that the system as planned does not have any reliability violations. Requiring PJM to use a transfer capability analysis in the planning horizon would require PJM to unwind our current FERC approved integrated queue study process for transmission service, merchant transmission, and generation interconnection.
Yes
The ATC Methodology used in the operations horizon is fundamentally different than how PJM designs the transmission system to accommodate new requests for transmission service and generation interconnection. Specifically, the long-term Firm transmission service evaluation doesn't start with a Transfer Capability analysis; the AFC/ATC methodology used in planning for operations does.
No
Revised purpose statement: To ensure that Planning Coordinators use an established method for effective, reliable planning of the Bulk Electric System (BES). Note: This methodology does not need to involve the calculation of transfer capability in the planning horizon
Yes

Yes
See answers to questions 4 and 5
Group
SERC Planning Standards Subcommittee
Philip R. Kleckley
No
Order 729 expresses FERC's "concerns" that the criteria used for the calculation of transfer capability be consistent in the Operations and Planning horizons. The SAR as drafted requires Planning Coordinators to document their methods and document the extent to which those methods differ between the operating and planning horizons. The SAR as drafted appears to go beyond the intent of FERC's language in 729 in that it requires methods to be consistent as opposed to criteria. If methods differ, but use the same criteria (i.e. 100% of normal facility ratings), then compliance should be achievable as many entities use different methods in the operating and planning horizons. We agree with the MISO comment that it is not clear if the draft standard provides sufficient details on the data inputs and modeling assumptions as directed from originally in Order 693.
No
We are concerned that more transfer capability studies than are needed will be required.
Yes
No
While we agree with the PTC definition we recommend that the phrase "implementation of a method" in the PTCID definition be replaced with the term "methodology" and the name of the document be changed to "Planning Transfer Capability Methodology Document (PTCMD)."
Yes
No
The SAR goes beyond what was identified as "concerns" by FERC, see response to Question 1.
No
We agree with the MISO comment that Measure 4 is not consistent with the requirement. The requirement requires recalculation once a calendar year and the measure attempts to require recalculation once a quarter.
No
R1 and R4 should have a VRF of "Lower". Calculation of PTCs will not directly lead to BES risk. The second alternative for High VSL for R1 should be graduated from Lower to Severe.
No

Yes
We recommend that part 5.2 under R5 be restated as: “Any other entities that demonstrate that they have a reliability-related need for such PTCs and make a written request for such PTCs.” We recommend that part 1.1 under R1 be restated as: “A list of all Transmission Operators for which the Planning Coordinator determines Planning Transfer Capabilities. Include the following for each of these Transmission Operators.” In the first bullet under D.1.4, change “ATCID” to “PTCID.” We agree with the MISO comments that: 1) It is not clear why the document focuses on Transmission Operators and not the traditional way in calculating transfer capabilities such as from BA to BA, region to region, sub-region to sub-region. The document should simply require the PC to identify what necessary interfaces it will calculate transfer capabilities on. 2) R2 and R3 should be combined into a single requirement. R2 in essence requires pre-notification of coming changes to the PTCID but there is no need to specify what the changes are. Then R3 requires notification again to the same entities with an actual copy of the changes. R2 as written is an administrative requirement that provides no reliability benefit. The comments expressed herein represent a consensus of the views of the above named members of the SERC Planning Standards Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board or its officers.
Group
FirstEnergy
Doug Hohlbaugh
Yes
The purpose statement of the SAR states "Address FERC directives from Order 729 Related to FAC-012-1 and FAC-013-1." By extension, Order 729 in paragraph 291 also requires NERC to address its Order 693 directives as well as those explicitly stated in Order 729. The SAR clearly contains excerpted directives from FERC Order 693 and 729 and to the best of our knowledge captures the Commission directives.
Yes
No
The SAR should allow sufficient flexibility for the drafting team to consider other responsible entities that may be required to support and provide information to the Planning Coordinator in this effort. While we agree that most and possibly all requirements will fall to the PC, the SAR should not be so narrowly written to preclude other entities if needed.
No
FE believes that the Planning Transfer Capability definition is not needed as the existing terms for Total Transfer Capability and Transfer Capability should suffice and that it should be well understood that the timeframe for this standard is the planning horizon. We support the PTCID definition with the following conforming change: "A document that describes the implementation of a method for calculating Total Transfer Capability (TTC) for a Planning Horizon and provides information related to a Planning Coordinator’s calculation of TTC."
Yes
Yes
No

The draft standard does not appear to include a requirement “that the criteria used to calculate planning capabilities for use in planning be identical to the criteria used to calculate available transfer capability and to operate the system.”
No
The measures will need to be adjusted for the suggested changes in our response to item 9 above.
Yes
No
Yes
Each requirement shows a time horizon of “Planning”, however, this is not a defined horizon. There are two types of planning horizons defined by NERC, “Long-Term Planning” and “Operations Planning”. The SDT should clarify the intent is Long-Term Planning.
Group
IRC Standards Review Committee
Ben Li
Yes
Yes
Yes
No
We do not see the need for defining the term Planning Transfer Capability (PTC). The current term Transfer Capability and its definition have been adopted for a long period of time. The industry is familiar with this definition, and have a deep and unambiguous understanding that in general term, it is the attainable level of power transfer from one point to another or on a specific transmission path (similarly, TTC is the maximum level of power transfer). The proposed definition is not needed since it quotes transfer capability which is already a defined term in the NERC Glossary, as follows: Transfer Capability: The measure of the ability of interconnected electric systems to move or transfer power in a reliable manner from one area to another over all transmission lines (or paths) between those areas under specified system conditions. The units of transfer capability are in terms of electric power, generally expressed in megawatts (MW). The transfer capability from “Area A” to “Area B” is not generally equal to the transfer capability from “Area B” to “Area A.” If the reason to create this definition is to make a distinction that this is the term used for planning assessment in the context of this standard, then we believe that this can be achieved simply by adding the phrase “in the planning horizon” to the term Transfer Capability. We do not have a difficulty with the creation of the term “Transfer Capability Implementation Document for so long as the word “Planning” is removed. Note that CAISO does not sign on to this specific comment.
No
We do not support the word “Planning” before “Transfer Capabilities” for reasons as indicated under Q6, above. Words such as “Planning Coordinators and “reliable planning” already suffice to put the Transfer Capabilities in the proper time horizon perspective. Note

that CAISO does not sign on to this specific comment.
Yes
No
(1) Requirement R1 stipulates the information that must be provided in the TCID for planning, and identifies the need to explain and justify any differences in the method used that are not consistent with the method selected by the Transmission Operator and described in the associated Transmission Service Provider's Available Transfer Capability Implementation Document (ATCID). We support this requirement but do not think that the requirement as written is sufficient to address the FERC's concerns that: "….FAC-012-1 merely required the documentation of a transfer capability methodology without providing a framework for that methodology including data inputs and modeling assumptions". We understand the Requirement R1 is written to achieve consistency with the pertinent MOD standard (MOD-028 or MOD-029), but it is not clear to us that in the two related standards, the conditions stipulated in the FERC Order in terms of data input and modeling assumption are fully met. We suggest the SDT to review both the draft FAC-013 and the approved MOD standards to ascertain that the FERC's concerns are fully addressed. (2) We suggest R2 and R3 be combined by "Each Planning Coordinator shall make available its current [P]TCID to all of the following entities, and notify these entities before implementing a new or revised [P]TCID. (The [P] indicates our proposal to remove the word "Planning" for the two terms.) (3) We believe the Transmission Planner should be added to Part 2.1. (4) R5 as written may prohibit some entities that have a reliability-related need to obtain the calculated Transfer Capabilities, for example, the Reliability Coordinators. Also, the TCID need-to-know entities in R2 and the TC need-to-know entities in R5 are not consistent. We suggest to make them the same, with consideration of including the RCs in the list.
No
(1) M4 conveys different evidence requirements than the what R4 requires. R4 asks for annual verification of each of the four seasons' Transfer Capabilities. M4 asks for evidence of verification of the Summer and Winter TCs only, but for once every 3 months. They are very different that what's stipulated in the requirement. We suggest M4 be revised to: "Each Planning Coordinator have evidence that it verified, and if necessary recalculated, its TCs consistent with its TCID for each season (Spring, Summer, Fall, and Winter) for years two through five at least once each calendar year. Note that CAISO does not sign on to this specific comment. CAISO is concerned that the Requirement R4 is excessive. Requiring the PC to conduct planning assessments for the Summer and Winter seasons for each calendar year from years two through five, as in current practice across the continent, would suffice. Regardless, there is an inconsistency between Requirement R4 and Measure M4. (2) Some Measure may need to be revised depending on the SDT's response to our comments under Q9.
No
(1) The retention period for R2 and R3 (or to be combined as we suggest) may not provide the evidence needed if there has not been a change to the TCID in the past 24 months. Suggest to change the retention period to be the same as R1. (2) R2: The wording for Lower can be interpreted to mean that the responsible entity did not comply with the requirement even if it notified all entities before implementing a new TCID. We suggest to reword it to: "The Planning Coordinator notified one or more of the parties specified in R2 of a new or modified PTCID, but was late by up to 30 calendar days after its implementation. (3) R5: Unlike its R2 counterpart, timing is not factored into the VSLs. We suggest to add a second condition under each VSL as follows: Lower: The Planning Coordinator made the TCs available to one or more of the entities described in R5, Part 5.2, but was late by up to 30 calendar days after the 10 calendar day target. Moderate: The Planning Coordinator

made the TCs available to one or more of the entities described in R5, Part 5.2, but was late more than 30 calendar days after the 10 calendar day target. High: The Planning Coordinator made the TCs available to one or more of the entities described in R5, Part 5.1, but was late by up to 30 calendar days after the 10 calendar day target. Moderate: The Planning Coordinator made the TCs available to one or more of the entities described in R5, Part 5.1, but was late more than 30 calendar days after the 10 calendar day target. If the above suggestions are not adopted, then we suggest to add the condition “within 10 calendar days” at the end of each of the VSL. For example, the Lower VSL will read: “The Planning Coordinator made the TCs available to some, but not all, of the entities described in R5, Part 5.2 within 10 calendar days.” (4) Some of the VSLs may need to be revised depending on the SDT’s response to our comments under Q9.
No

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments on Project 2010-10 — Modifications to FAC-012 and FAC-013 for Order 729 — SAR and Draft FAC-013 Standard

The FAC Order 729 Drafting Team thanks all commenters who submitted comments on the proposed SAR and modifications proposed FAC-013-2 — Planning Transfer Capability. These documents were posted for a 45-day public comment period from March 15, 2010 through April 29, 2010. Stakeholders were asked to provide feedback on the standard through a special Electronic Comment Form. There were 15 sets of comments, including comments from over 60 different people from more than 30 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

Based on the comments received the drafting team made the following changes to the proposed Standard:

- Modified the definitions of Planning Transfer Capability (PTC) and Planning Transfer Capability Methodology Document (PTCMD).
- Modified the Purpose Statement to clarify that the requirements aim at preparation, not real time use of a methodology for calculating Planning Transfer Capabilities.
- Modified the Effective Date (from six months to twelve months) to allow sufficient time for the Planning Coordinator to prepare its PTCMD.
- Modified Requirement R1 to include data and modeling details and provide clarity.
- Modified the requirement to distribute the PTCMD to a larger group of entities, including entities with a reliability-related need who request the PTCMD
- Added a set of requirements to support peer review of the PTCMD
- Modified all Measures to better align with the Requirements.
- Modified the VRFs to align with the modifications to the Requirements.
- Modified the VSLs to align with the modifications to the Requirements.

In this "Consideration of Comments" document stakeholder comments have been organized so that it is easier to see the responses associated with each question. All comments received on the standards can be viewed in their original format at:

http://www.nerc.com/filez/standards/Project2010-10_FAC_Order_729.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Herbert Schrayshuen, at 609-452-8060 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Gregory Campoli	New York Independent System Operator	NPCC	2
3.	Roger Champagne	Hydro-Quebec TransEnergie	NPCC	2
4.	Kurtis Chong	Independent Electricity System Operator	NPCC	2
5.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
6.	Chris de Graffenried	Consolidated Edison co. of New York, Inc.	NPCC	1
7.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
8.	Ben Eng	New York Power Authority	NPCC	4
9.	Brian Evans-Mongeon	Utility Services	NPCC	8
10.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
11.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5
12.	Kathleen Goodman	ISO - New England	NPCC	2
13.	David Kiguel	Hydro One Networks Inc.	NPCC	1
14.	Michael R. Lombardi	Northeast Utilities	NPCC	1
15.	Randy MacDonald	New Brunswick System Operator	NPCC	2
16.	Bruce Metruck	New York Power Authority	NPCC	6
17.	Chris Orzel	FPL Energy/NextEra Energy	NPCC	5
18.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
19.	Robert Pellegrini		The United Illuminating Company	NPCC						1			
20.	Saurabh Saksena		National Grid	NPCC						1			
21.	Michael Schiavone		National Grid	NPCC						1			
22.	Peter Yost		Consolidated Edison Co. of New York, Inc.	NPCC						3			
2.	Group	Stephen Mizelle	Southern Company Transmission	X									
3.	Group	Jason L. Marshall	Midwest ISO Stakeholder Standards Collaborators		X								
	Additional Member		Additional Organization	Region						Segment Selection			
1.	Barb Kedrowski		We Energies	RFC						3, 4, 5			
2.	Joe O'Brien		NIPSCO	RFC						1			
3.	Joe Knight		Great River Energy	MRO						1, 3, 5, 6			
4.	Jim Cyrulewski		JDRJC Associates, LLC	RFC						8			
4.	Group	Denise Koehn	Bonneville Power Administration	X		X		X	X				
	Additional Member		Additional Organization	Region						Segment Selection			
1.	Laura Trolese		BPA - Transmission Policy Development & Analysis	WECC						1			
2.	Mike Viles		BPA - Transmission Technical Operations	WECC						1			
3.	Pat Rochelle		BPA - Transmission Planning	WECC						1			
4.	Jeff Newby		BPA - Transmission Planning	WECC						1			
5.	James Randall		BPA - Transmission Planning	WECC						1			
6.	Kyle Kohne		BPA - Transmission Planning	WECC						1			
7.	Rebecca Berdahl		BPA - Power Long Term Sales and Purchases	WECC						3			
5.	Group	Patrick Brown	PJM Interconnection		X								
	Additional Member		Additional Organization	Region						Segment Selection			
1.	Don Williams		PJM Interconnection	RFC						2			
2.	Chris Advena		PJM Interconnection	RFC						2			
3.	Mark Sims		PJM Interconnection	RFC						2			
6.	Group	Philip R. Kleckley	SERC Planning Standards Subcommittee	X		X		X					
	Additional Member		Additional Organization	Region						Segment Selection			
1.	Bob Jones		Southern Company Services - Trans.	SERC						1			
2.	David Marler		Tennessee Valley Authority	SERC						1			

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
3. Charles Long			Entergy	SERC						1			
4. James Manning			North Carolina Electric Membership Corporation	SERC						3			
5. Pat Huntley			SERC Reliability Corporation	SERC						NA			
7.	Group	Doug Hohlbaugh	FirstEnergy	X		X	X	X	X				
Additional Member			**Additional Organization**	**Region**						**Segment Selection**			
1. Sam Ciccone			FirstEnergy	RFC						1, 3, 4, 5, 6			
2. Dave Folk			FirstEnergy	RFC						1, 3, 4, 5, 6			
8.	Group	Ben Li	IRC Standards Review Committee		X								
Additional Member			**Additional Organization**	**Region**						**Segment Selection**			
1. Bill Phillips			MISO	MRO						2			
2. Lourdes Estrada-Salinero			CAISO	WECC						2			
3. James Castle			NYISO	NPCC						2			
4. Steve Myers			ERCOT	ERCOT						2			
5. Matt Goldberg			ISO-NE	NPCC						2			
6. Mark Thompson			AESO	WECC						2			
7. Charles Yeung			SPP	SPP						2			
8. Patrick Brown			PJM	RFC						2			
9.	Individual	Ross Kovacs	Georgia Transmission Corporation	X									
10.	Individual	Kirit Shah	Ameren	X		X		X	X				
11.	Individual	Dan Rochester	Independent Electricity System Operator		X								
12.	Individual	Kasia Mihalchuk	Manitoba Hydro	X		X		X	X				
13.	Individual	Jon Kapitz	Xcel Energy	X		X		X	X				
14.	Individual	Darcy O'Connell	California ISO		X								
15.	Individual	Greg Rowland	Duke Energy	X		X		X	X				

1. Do you agree that the SAR fully addresses the applicable directives from FERC Order 693 and Order 729?

Summary Consideration: Most stakeholders who responded to this question indicated that the SAR does fully address the applicable directives from FERC Order 693 and Order 729.

A few of the entities providing comments felt that the RC should be removed from the draft standard. There are no references to the Reliability Coordinator in the proposed standard.

A couple of the entities providing comments felt that the standard was implying that it could be used to grant transmission rights. The SDT removed any reference to transfer capability calculations.

A few of the commenters felt that the standard was mandating that the methodologies needed to be consistent rather than the criteria used in the methodology. The SDT modified the standard to include data and modeling details to establish a framework and consistency for the Planning Transfer Capability (PTC) methodology while allowing the Planning Coordinators the flexibility necessary for their individual methodology.

The following was added to Requirement R1 as information (data and modeling details) that must be provided in the Planning Coordinator's Planning Transfer Capability Methodology:

1.1. A description of how each of the following is addressed in the calculation of Planning Transfer Capabilities (PTC), or an explanation for any of the following not used in the calculation of PTC.

- Generation dispatch, including expected outages, additions and retirements
- Transmission system topology, including expected transmission outages, additions and retirement
- System demand
- Current and projected transmission uses
- Parallel path impacts (loop flow)
- Contingencies
- Reliability margins applied to reflect uncertainty with BES conditions.

1.2. A list of all PTC's to be calculated.

1.3. A statement that PTC's shall respect all applicable System Operating Limits (SOL's).

1.4. A statement that the assumptions and criteria used to calculate PTC are as or more limiting than the assumptions and criteria used in the operating horizon.

1.5. A description of how generation/load is adjusted to determine the PTC's identified in 1.2 above.

1.6. A description of the assumptions and criteria used to calculate PTC.

Organization	Yes or No	Question 1 Comment
Ameren	No	Draft Standard does not appear to provide details on the data input and modeling assumptions from Order 693.
Response: The SDT has added data and modeling details to R1 to establish a framework and consistency for the PTC methodology but still allowing for flexibility for individual Planning Coordinators.		
Manitoba Hydro	No	Manitoba Hydro does not believe FERC should mandate changes to international standards. Order 729 required elimination of redundancies between FAC-012 and the new MOD standards (1, 28-30). This can easily be accomplished by removing reference to the Reliability Coordinator in R1 through R4. Order 693 required a more detailed framework of the data inputs and modeling assumptions. This could be added as an additional requirement R1.4 in the existing FAC-012 standard. There is no strong reliability need to have a consistent methodology between the operating and planning horizons. However, there should be a need to ensure the methodologies used by adjacent Planning Coordinators for the same interface are consistent. Requirement R4 is a step in this direction in the existing standard but is completely missing in the revised standard. The proposed changes make the Transfer Capability calculations in the 2-5 year period too close to a full operational study. This is not consistent with the direction given by Order 729 and 693 where the numbers are not intended to grant transmission service.
Response: With reference to your comment concerning FERC jurisdiction, this is an issue that is outside the scope of this project. **There are no references to the Reliability Coordinator in the set of proposed revisions to the standard.** **The SDT has added data and modeling details to R1 to establish a framework and consistency for the PTC methodology but still allowing for flexibility for individual Planning Coordinators.** **The SDT believes that the present communication flow on PTC and PTCMD's is sufficient to ensure reliability and the methods do not need to be consistent.** **The draft standard has been modified to remove any reference to transfer capability calculations for use in ATC calculations in the operational horizon.**		
SERC Planning Standards Subcommittee	No	Order 729 expresses FERC's "concerns" that the criteria used for the calculation of transfer capability be consistent in the Operations and Planning horizons. The SAR as drafted requires Planning Coordinators to document their methods and document the extent to which those methods differ between the operating and

Organization	Yes or No	Question 1 Comment
		planning horizons. The SAR as drafted appears to go beyond the intent of FERC's language in 729 in that it requires methods to be consistent as opposed to criteria. If methods differ, but use the same criteria (i.e. 100% of normal facility ratings), then compliance should be achievable as many entities use different methods in the operating and planning horizons. We agree with the MISO comment that it is not clear if the draft standard provides sufficient details on the data inputs and modeling assumptions as directed from originally in Order 693.
Response: The SDT has added data and modeling details to R1 to establish a framework and consistency for the PTC methodology but still allowing for flexibility for individual Planning Coordinators.		
Midwest ISO Stakeholder Standards Collaborators	No	The SAR appears to fully address the directives; however, it is not clear if the draft standard provides sufficient details on the data inputs and modeling assumptions as directed in Order 693.
Response: The SDT has added data and modeling details to R1 to establish a framework and consistency for the PTC methodology but still allowing for flexibility for individual Planning Coordinators.		
Duke Energy	Yes	However, we don't believe that it's possible to maintain a strict adherence to the FERC directive that the methodology and criteria used to determine Planning Transfer Capability (PTC) in the planning timeframe be identical to, or even consistent with, those used in determining ATC in the operating timeframe. The methodologies and criteria need to be different in some instances because the objectives are different. In the operating timeframe, realistic assumptions and data reflecting the expected operating conditions of the system must be used for determining ATC. In the planning timeframe, different assumptions for operating conditions and contingencies are used to determine how robust the system is in response to more extreme events. For example, a study might examine the impacts of significantly reduced generation from unscrubbed coal plants. Furthermore, analyses in the planning timeframe may use different tools (and thus treat inputs differently) such as PSSE, versus an ATC tool such as MUST.
Response: The SDT thanks you for your affirmative response and clarifying comment. The SDT has added data and modeling details to R1 to establish a framework and consistency for the PTC methodology but still allowing for flexibility for individual Planning Coordinators.		
Southern Company Transmission	Yes	Southern believes the description of the SAR fully addresses the applicable directives from FERC Order 693 and FERC Order 729. Southern interprets the main directives from these respective orders as: 1) modify FAC-12-1 and FAC-13-1 to address calculation and communication of Transfer Capabilities for the timeframe beyond 13 months, 2) modifications to these FAC standards should not address the timeframe from 1 hour through 13 months, 3) modify FAC-13 to be applicable to the Planning Coordinator only and not the Reliability Coordinator, and 4) remove redundant provisions for the calculation of Transfer Capabilities addressed elsewhere in the MOD

Organization	Yes or No	Question 1 Comment
		Reliability Standards. Southern agrees with NERC's interpretation that the revised FAC standards must not conflict with the ATC-related MOD standards as long as NERC's interpretation is that the revised FAC standards do not prescribe additional requirements for the calculation of Transfer Capabilities in the operating horizon. However, Southern would disagree if NERC's interpretation is that the methodologies described in the MOD Reliability Standards (MOD-28-1, MOD-29-1, and MOD-30-2) must be utilized to calculate Transfer Capabilities for the timeframe beyond 13 months. Southern does not believe that there are existing standards that provide the framework for calculation of Transfer Capabilities beyond 13 months.
Response: The SDT thanks you for your affirmative response and clarifying comment. The SDT has modified the standard to remove any reference to transfer capability calculations for use in ATC calculations in the operational horizon. **The SDT has modified the standard to provide a framework for beyond 13 months.**		
FirstEnergy	Yes	The purpose statement of the SAR states "Address FERC directives from Order 729 Related to FAC-012-1 and FAC-013-1." By extension, Order 729 in paragraph 291 also requires NERC to address its Order 693 directives as well as those explicitly stated in Order 729. The SAR clearly contains excerpted directives from FERC Order 693 and 729 and to the best of our knowledge captures the Commission directives.
Response: The SDT thanks you for your affirmative response and clarifying comment.		
Xcel Energy	Yes	The SAR appears to fully address the directives; however, it is not clear if the draft standard provides sufficient details on the data inputs and modeling assumptions as directed from originally in Order 693.
Response: The SDT thanks you for your affirmative response and clarifying comment. **The SDT has added data and modeling details to R1 to establish a framework and consistency for the PTC methodology but still allowing for flexibility for individual Planning Coordinators.**		
California ISO	Yes	
Georgia Transmission Corporation	Yes	
Independent Electricity System Operator	Yes	
IRC Standards Review Committee	Yes	

Organization	Yes or No	Question 1 Comment
Northeast Power Coordinating Council	Yes	
PJM Interconnection	Yes	

2. Do you agree with the scope of the proposed standards action?

Summary Consideration: One commenter questioned the relationship between FAC-010-2/FAC-014-2 and FAC-013-2. There is no relationship between FAC-010/FAC-014 and FAC-013.

- FAC-010/FAC-014 deal with calculation and communication of System Operating Limits (SOLs) and the subset of SOLs that are also Interconnection Reliability Operating Limits (IROLs) based on specific criteria contained in the standards.
- FAC-013-2 requires calculation of Planning Transfer Capabilities (PTCs) according to the Planning Coordinator's Planning Transfer Capability Implementation Document (PTCID), based on the Planning Coordinator's own set of criteria. Note that in the revised standard, the PTCID has been changed to Planning Transfer Calculation Methodology Document (PTCMD).

The PTC can be calculated between areas where no SOL has been established; PTC's are calculated to enhance the Planning Coordinator's understanding of the system behavior and not to establish operating limits.

Another commenter stated that it would put a strain on the Planning Coordinator to determine planning horizon PTC's, and that the Transmission Operator would not be interested in Planning Horizon PTC's. The development of PTCs is not unnecessary work; there is a reliability related need to calculate PTC's in accordance with the PTCID (now called PTCMD) based on knowledge of how the system operates. This is consistent with existing industry practice. The standard had been modified and no longer requires the information to be shared with a Transmission Operator.

Organization	Yes or No	Question 2 Comment
Bonneville Power Administration	No	BPA would like clarification regarding the relationship between FAC-010-2 and FAC-014-2 and the proposed FAC-013-2, specifically regarding the difference between establishing a System Operating Limit in the Planning Horizon and establishing Planning Transfer Capabilities.
Response: There is no relationship between the FAC-010/FAC-14 and FAC-013. FAC-010/FAC-14 deal with calculation and communication of SOLs and the subset of SOLs that are IROL's based on specific criteria contained in the standards and are applicable to different entities. FAC-013 only requires calculation of PTC's according to the Planning Coordinator's PTCID (now called the PTCMD), which is based on the PC's criteria. For instance, PTC may be calculated between areas where no SOL is established. PTC's are calculated to enhance the Planning Coordinators understanding of system behavior not to establish system operating limits.		
Duke Energy	No	The granularity of the proposed standards action is too great. And there is too much linkage between PTCID and ATCID that is not achievable, or even desirable, since the ATCID addresses transfer capability to support reliable operation of the system, while PTCID addresses planning of the system for reliability under a potentially wide range of future conditions.

Organization	Yes or No	Question 2 Comment
Response: The SDT believes sufficient flexibility has been afforded by allowing calculation of PTC's according to the Planning Coordinator's PTCMD. The SDT agrees with your comment regarding the excessive amount of linkage between PTCID and ATCID and has removed all linkage between the two.		
Manitoba Hydro	No	The SAR requires the PC to complete many detailed studies and verifications. This is unnecessary work in determining planning horizon PTCs.The SAR assumes TOs have a large interest in Planning Horizon PTCs. This is not always the case.
Response: The SDT disagrees and believes there is a reliability related need to calculate PTC's according to the Planning Coordinator's PTCMD based on their knowledge of how the system operates. This is consistent with existing industry practice. This standard has been modified and no longer requires this information to be shared with Transmission Operators.		
SERC Planning Standards Subcommittee	No	We are concerned that more transfer capability studies than are needed will be required.
Response: The SDT has modified the draft standard to better align the number of Transfer Capability studies with what is required for reliability.		
Ameren	Yes	
California ISO	Yes	
FirstEnergy	Yes	
Georgia Transmission Corporation	Yes	
Independent Electricity System Operator	Yes	
IRC Standards Review Committee	Yes	
Midwest ISO Stakeholder Standards Collaborators	Yes	
Northeast Power Coordinating Council	Yes	

Organization	Yes or No	Question 2 Comment
PJM Interconnection	Yes	
Southern Company Transmission	Yes	
Xcel Energy	Yes	

3. Do you agree that the Planning Coordinator is the only functional entity that should have requirements assigned to them as part of this project? If not, please identify to whom the standard should apply and why.

Summary Consideration: A couple of entities that provided comments suggested that this standard was requiring duplication of data already provided for in other standards. The SDT does not believe that there is any duplication.

Some commenters indicated that there may be some gaps in data provision such additional requirements may be needed to ensure the Planning Coordinator has the data needed to calculate Planning Transfer Capabilities. The necessary data and information is available to the Planning Coordinator through requirements in other standards as well as through participation in FERC Order 890 activities - this standard is not requiring additional reporting of the same data.

Another commenter felt that the standard should require coordination of the verification of PTC with the Transmission Planner (TP). Sharing the information with the TP's allowed the TP to review the information and therefore was sufficient coordination.

Organization	Yes or No	Question 3 Comment
Midwest ISO Stakeholder Standards Collaborators	No	The drafting team should review if there are any requirements needed to compel registered entities such as TP, TO, TOP, GO, GOP, and BA to provide any data that the PC needs to complete its function. If the data is already required through other requirements in other standards, then additional requirements are not needed.
Response: The SDT believes the necessary data and information is available to the Planning Coordinator through the requirements of other NERC standards and participation in FERC Order 890 activities.		
FirstEnergy	No	The SAR should allow sufficient flexibility for the drafting team to consider other responsible entities that may be required to support and provide information to the Planning Coordinator in this effort. While we agree that most and possibly all requirements will fall to the PC, the SAR should not be so narrowly written to preclude other entities if needed.
Response: The SDT believes the necessary data and information is available to the Planning Coordinator through the requirements of other NERC standards and participation in FERC Order 890 activities. No additional responsible entities were added to the SAR.		
Ameren	No	We believe that, in R4, PC should coordinate verification of PTC with TP(within PC's planning coordinator area).
Response: The SDT believes that sharing the information with the TP's is sufficient coordination as required in Requirement R5. The SDT added requirements to include peer review of the PTCMD, in support of your suggestion.		

Organization	Yes or No	Question 3 Comment
Xcel Energy	Yes	We agree, however the mapping of entities to Planning Coordinators is an ongoing gap in the registration process. Many entities (primarily non-RTO) are unable to point to who their PC is and similarly, entities who are PCs self define the entities they cover. To our knowledge, there is no source to identify the mapping of these relationships. Therefore, prior to implementation of standards that propose very prescriptive requirements on the PC and their interactions with subordinate entities it is important that the relationships are clearly established as a point of reference.
Response: Your comment concerning the registration process is outside the scope of this project.		
California ISO	Yes	
Duke Energy	Yes	
Georgia Transmission Corporation	Yes	
Independent Electricity System Operator	Yes	
IRC Standards Review Committee	Yes	
Manitoba Hydro	Yes	
Northeast Power Coordinating Council	Yes	
PJM Interconnection	Yes	
SERC Planning Standards Subcommittee	Yes	
Southern Company Transmission	Yes	

4. If you are aware of the need for a regional variance or business practice that we should consider with this SAR, please identify it here.

Summary Consideration: Only two entities responded to this question. One entity felt that a regional business practice difference should be considered since WECC allows these calculations to be used to establish path ratings. The draft standard only requires that PTCs be calculated - how PTCs are used or applied is the responsibility of the entity using the PTCs.

The other entity stated disagreement with a need to calculate PTCs. The draft standard only requires PTCs to be calculated where the Planning Coordinator feels there is a need in accordance with its PTCMD - PTCs provide additional important information used when assessing reliability in the planning horizon.

Organization	Yes or No	Question 4 Comment
Duke Energy		none
Xcel Energy	Business Practice	Business Practice: WECC Planning Coordination Committee (PCC) HandbookComments: Entities within WECC may be using this to establish path ratings
Response: The standard requires the calculation of PTC's. How the information is used and applied is the responsibility of the entities using the information.		
PJM Interconnection	Business Practice	PJM does not believe that a transfer capability methodology is the only valid option for the planning horizon. PJM's current, FERC approved, integrated queue study process (part of the PJM Regional Transmission Expansion Planning Process) requires that PJM study the base system and resolve any reliability criteria violations by implementing system upgrades. PJM then studies the integrated queue in the order in which the queued projects were received and resolves any reliability criteria violations by implementing system upgrades. This method ensures that the system as planned does not have any reliability violations. Requiring PJM to use a transfer capability analysis in the planning horizon would require PJM to unwind our current FERC approved integrated queue study process for transmission service, merchant transmission, and generation interconnection.
Response: The revised FAC-013 only requires calculation of PTC's where the Planning Coordinator has determined a need for PTC's to be calculated. PTC's are to be calculated according to the Planning Coordinator's PTCID, which is based on their criteria. This provides additional important information for assessing reliability in the planning horizon.		

5. **If you have any other comments on this SAR that you have not already provided in response to the prior questions, please provide them here.**

Summary Consideration: There were only two entities who provided comments in response to this question. In both cases the entities appeared to be confusing calculating available AFC/ATC with calculating PTCs. The SDT acknowledged that the first draft of the standard was confusing. The SDT removed all references to transfer capability for use in AFC/ATC calculations in the operational timeframe from the second draft of the proposed standard.

Organization	Yes or No	Question 5 Comment
Duke Energy	No	
Southern Company Transmission	No	
Xcel Energy	No	
PJM Interconnection	Yes	The ATC Methodology used in the operations horizon is fundamentally different than how PJM designs the transmission system to accommodate new requests for transmission service and generation interconnection. Specifically, the long-term Firm transmission service evaluation doesn't start with a Transfer Capability analysis; the AFC/ATC methodology used in planning for operations does.
Response: The draft standard has been modified to remove any reference to transfer capability calculations for use in ATC calculations in the operational horizon.		
Manitoba Hydro		The SAR requires that the PTCID line up with the ATC methodology in the operating horizon (the ATCID). This implies full blown operating studies in the planning horizon (spring. Summer, fall winter years 2 to 5). The accuracy and uncertainty of planning horizon PTCs mean these PTCs will not necessarily allow for transmission service. So why is it necessary for PCs to do the detailed work required to ensure the PTCID line up with the ATC methodology in the operating horizon (the ATCID)?
Response: The draft standard has been modified to remove any reference to transfer capability calculations for use in ATC calculations in the operational horizon.		

6. The draft standard proposes two new definitions.

Planning Transfer Capability (PTC): A forecast of the Transfer Capability between areas that is used in the Near-Term Planning Horizon and Long-Term Planning Horizon when performing planning analyses.

Planning Transfer Capability Implementation Document (PTCID): A document that describes the implementation of a method for calculating PTC, and provides information related to a Planning Coordinator's calculation of PTC.

Do you agree with the proposed definitions in the draft standard?

Summary Consideration: Some of the commenters indicated that the PTC definition was not needed and was covered by Total Transfer Capability (TTC) and Transfer Capability (TC). The SDT explained that the term (PTC) is needed to avoid any confusion with the terms the commenter identified, TTC and TC. The terms PTC, TTC and TC have different meanings and purposes. The draft standard was not intended to address TTC calculations.

A few commenter's questioned the relationship between FAC-010-2 and FAC-013-2. There is no relationship between FAC-010-2 and FAC-013-2. FAC-010-2 deals with calculation of SOLs and the subset of SOLs that are IROLs, based on specific criteria contained in the standards - while FAC-013-2 requires calculation of PTCs according to the Planning Coordinator's PTCID (now PTCMD in the second draft of the standard), which are based on the PC's own set criteria. PTCs could be calculated between areas where no SOLs have been established; PTCs are calculated to enhance the Planning Coordinator's understanding of the system behavior and not to establish operating limits.

A couple of commenters questioned the use of the phrase "A forecast of the" in the definition of PTC and stated that the planning horizon has not been defined. The SDT agrees with the commenter and modified the definition to now read "The Transfer Capability that is calculated for the planning period (beyond 13 months)."

Another commenter objected to the use of the phrase "implementation of a method" and suggested that the name of the document be changed to Planning Transfer Capability Methodology Document (PTCMD). The SDT agrees and has revised both the name and the definition. The definition of PTCMD now reads "A document that describes the process for calculating Planning Transfer Capability (PTC)."

Planning Transfer Capability (PTC): The Transfer Capability that is calculated for the planning period (beyond 13 months).

Planning Transfer Capability Implementation Document (PTCID): A document that describes the implementation of a method for calculating Planning Transfer Capability (PTC), and provides information related to a Planning Coordinator's calculation of PTC.

Organization	Yes or No	Question 6 Comment
FirstEnergy	No	FE believes that the Planning Transfer Capability definition is not needed as the existing terms for Total Transfer Capability and Transfer Capability should suffice and that it should be well understood that the timeframe for this standard is the planning horizon. We support the PTCID definition with the following conforming change: "A document that describes the implementation of a method for calculating Total Transfer Capability (TTC) for a Planning Horizon and provides information related to a Planning Coordinator's calculation of TTC."
Response: The SDT believes the PTC term is necessary to avoid confusion with other forms of transfer capability (i.e. TTC and ATC) that have a different meaning and purpose. **This draft standard is not intended to address TTC calculations.**		
Southern Company Transmission	No	In general, Southern agrees with the proposed definitions of PTC and PTCID; however, Southern would like to propose a revision to the definition of PTC to capture that PTC is the forecast of Transfer Capabilities beyond the 13 month timeframe. The calculations of Transfer Capabilities within the timeframes from 1 hour up to 13 months have been adequately covered by the MOD Reliability Standards approved within FERC's Order 729. Additionally, the term "Planning Horizon" is not a term currently defined in the NERC Glossary. Although FERC implied in Order 729 that the planning horizon is years one through five, Southern recommends that NERC either define the term Planning Horizon or rephrase the definition of PTC to capture the applicable timeframe as specified in FERC Order 729 without referencing the term Planning Horizon.
Response: The SDT agrees and has modified the standard to only require calculation of PTC's beyond 13 months.		
Georgia Transmission Corporation	No	The definition of Planning Transfer Capability is inconsistent with the definitions of ATC in MOD-001-1 and TTC in MOD-028-1, MOD-029-1, and MOD-030-2. ATC and TTC in the MOD standards are calculated for each ATC Path. A more consistent definition would be "A forecast of the transfer capability for each ATC Path that is used in the Planning Horizon when performing planning analyses". GTC notes that Order 729, paragraph 279 states, "The Commission also expressed concern that the criteria used to calculate transfer capabilities for use in determining available transfer capability must be identical to those used in planning and operating the system. The Commission directed the ERO to modify FAC-012-1 to provide a framework for the transfer capability calculation methodology that takes account of the need for consistency in the criteria used to calculate transfer capabilities."
Response: The Planning Coordinator should be afforded the flexibility to include more or fewer paths in their PTCID if they believe it appropriate. **The SDT has added data and modeling details to R1 to establish a framework and consistency for the PTC methodology but still allowing for flexibility for individual Planning Coordinators.**		

Organization	Yes or No	Question 6 Comment
Bonneville Power Administration	No	The definition of Planning Transfer Capability is vague. It is unclear if Planning Transfer Capability is meant to be different than Total Transfer Capability in the Planning Horizon. Is Planning Transfer Capability the same as Total Transfer Capability in the Planning Horizon? If not, how are they different? How does PTC relate to the requirements in FAC-010-2 regarding determination of the System Operating Limit for the Planning Horizon? BPA disagrees with the proposed definition of PTC and does not see the need for this new term.
Response: The PTC is not the same as the TTC. This draft standard is not intended to address TTC calculations. **There is no relationship between the FAC-010 and FAC-013. FAC-010 deals with calculation of SOL and IROL's based on specific criteria contained in the standard. FAC-013 only requires calculation of PTC's according to the Planning Coordinator's PTCID, which is based on their criteria. For instance, PTC may be calculated between areas where no SOL is established. PTC's are calculated to enhance the Planning Coordinators understanding of system behavior not to establish system operating limits.**		
Manitoba Hydro	No	The PTC definition should refer to 'interfaces', not 'areas'. It should align with R1.1.1 which refers to interfaces. The PTC is a transfer capability not a forecast of a transfer capability.Proposed PTC definition: Planning Transfer Capability: The measure of the ability of interconnected electric systems to move or transfer power in a reliable manner from one area to another over all transmission lines (or paths) between those areas under specified system conditions in the planning horizon of one year or longer.The group of lines or paths between adjacent areas comprise an interface.Why is it necessary to have a new definition instead of using the definition of Transfer Capability in the NERC Glossary: The measure of the ability of interconnected electric systems to move or transfer power in a reliable manner from one area to another over all transmission lines (or paths) between those areas under specified system conditions. The units of transfer capability are in terms of electric power, generally expressed in megawatts (MW). The transfer capability from "Area A" to "Area B" is not generally equal to the transfer capability from "Area B" to "Area A."The standard could just refer to "Transfer Capability in the planning horizon. Planning horizon should be defined. The PTCID definition is unnecessarily wordy. Also, the PTCID should describe a method not an 'implementation of a method'.Proposed PTCID definition: PTCID: A document that describes the method for calculating PTC.
Response: The SDT has removed the references to "areas" from the definition of PTC. The term "interfaces" has also been removed from what used to be Requirement R1.1.1 (now R1.2) from this draft of the standard and simply requires a list of the PTCs to be calculated. Requirement R1.2 now reads "A list of all Planning Transfer Capabilities (PTC) to be calculated." **The SDT agrees with your comment regarding the phrase "A forecast of the". The SDT has revised the definition and it now reads "The Transfer Capability that is calculated for the planning horizon (beyond 13 months)". This also addresses your concern with defining planning horizon.** **The SDT believes the PTC term is necessary to avoid confusion with other forms of transfer capability (i.e. TTC and ATC) that have a different meaning and purpose.** **The SDT has revised the draft standard to require documentation of their method for calculating PTC.**		

Organization	Yes or No	Question 6 Comment
Xcel Energy	No	There is no need to create the term Planning Transfer Capability (PTC). Transfer Capability is a well understood long standing NERC defined term and should be used in its place. Furthermore, the proposed definition is not consistent with the Transfer Capability or Total Transfer Capability definitions.
Response: The SDT believes the PTC term is necessary to avoid confusion with other forms of transfer capability (i.e. TTC and ATC) that have a different meaning and purpose. **The SDT has capitalized "Transfer Capability" in the definition to make clear that this is based on the NERC Glossary of Terms and is not Total Transfer Capability, which is a separate term.**		
Independent Electricity System Operator	No	We do not see the need for defining the term Planning Transfer Capability (PTC). The current term Transfer Capability and its definition have been adopted for a long period of time. The industry is familiar with this definition, and have a deep and unambiguous understanding that in general term, it is the attainable level of power transfer from one point to another or on a specific transmission path (similarly, TTC is the maximum level of power transfer). We view the proposed definition as redundant since it is similar to the definitions of Transfer Capability and Total Transfer Capability already in the NERC Glossary, viz.:Transfer Capability: The measure of the ability of interconnected electric systems to move or transfer power in a reliable manner from one area to another over all transmission lines (or paths) between those areas under specified system conditions. The units of transfer capability are in terms of electric power, generally expressed in megawatts (MW). The transfer capability from "Area A" to "Area B" is not generally equal to the transfer capability from "Area B" to "Area A."Total Transfer Capability:The amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions.If the reason to create this definition is to make a distinction that this is the term used for planning assessment in the context of this standard, then we believe that this can be achieved simply by adding the phrase "in the planning horizon" to the term Transfer Capability. We do not have a difficulty with the creation of the term "Transfer Capability Implementation Document for so long as the word "Planning" is removed.
Response: The SDT believes the PTC term is necessary to avoid confusion with other forms of transfer capability (i.e. TTC and ATC) that have a different meaning and purpose. The SDT revised the definition of PTC in support of your suggestion and eliminated the language that duplicated the definition of transfer capability. Based on comments from other stakeholders, the definition of PTCID was changed to PTCMD to clarify that the document focuses on the 'methodology' for calculating Planning Transfer Capability rather than 'implementation' of that methodology.		
IRC Standards Review Committee	No	We do not see the need for defining the term Planning Transfer Capability (PTC). The current term Transfer Capability and its definition have been adopted for a long period of time. The industry is familiar with this definition, and have a deep and unambiguous understanding that in general term, it is the attainable level of power transfer from one point to another or on a specific transmission path (similarly, TTC is the maximum level of power transfer). The proposed definition is not needed since it quotes transfer capability which is already a defined term in the NERC Glossary, as follows:Transfer Capability: The measure of the ability of

Organization	Yes or No	Question 6 Comment
		interconnected electric systems to move or transfer power in a reliable manner from one area to another over all transmission lines (or paths) between those areas under specified system conditions. The units of transfer capability are in terms of electric power, generally expressed in megawatts (MW). The transfer capability from “Area A” to “Area B” is not generally equal to the transfer capability from “Area B” to “Area A.”If the reason to create this definition is to make a distinction that this is the term used for planning assessment in the context of this standard, then we believe that this can be achieved simply by adding the phrase “in the planning horizon” to the term Transfer Capability.We do not have a difficulty with the creation of the term “Transfer Capability Implementation Document for so long as the word “Planning” is removed.Note that CAISO does not sign on to this specific comment.
Response: The SDT believes the PTC term is necessary to avoid confusion with other forms of transfer capability (i.e. TTC and ATC) that have a different meaning and purpose.		
Northeast Power Coordinating Council	No	We do not see the need for defining the term Planning Transfer Capability (PTC). The current term Transfer Capability and its definition have been in use for a long period of time. The industry is familiar with this definition, and has an understanding that it is the attainable level of power transfer from one point to another or on a specific transmission path (similarly, TTC is the maximum level of power transfer). The proposed definition is not compatible with either the definition of Transfer Capability or the definition of Total Transfer Capability in the NERC Glossary, as follows:Transfer Capability: The measure of the ability of interconnected electric systems to move or transfer power in a reliable manner from one area to another over all transmission lines (or paths) between those areas under specified system conditions. The units of transfer capability are in terms of electric power, generally expressed in megawatts (MW). The transfer capability from “Area A” to “Area B” is not generally equal to the transfer capability from “Area B” to “Area A.”Total Transfer Capability:The amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions.If this definition was created to emphasize that this is the term used for planning assessment in the context of this standard, then this could be achieved simply by adding the phrase “in the planning horizon” to the term Transfer Capability. We accept the creation of the term “Transfer Capability Implementation Document". “Planning” should be removed.
Response: The SDT believes the PTC term is necessary to avoid confusion with other forms of transfer capability (i.e. TTC and ATC) that have a different meaning and purpose.		
Ameren	No	What is the need for PTC? We believe that well established NERC terms like ATC, TTC, FCITC should be used. The proposed definition of PTC is not consistent these terms. Furter, we have several questions with regard to PTC : Is PTC simultaneous or non-simultaneous? How is PTC will be used? Is PC going to decide how it would be used?
Response: The SDT believes the PTC term is necessary to avoid confusion with other forms of transfer capability (i.e. TTC and ATC) that have a		

Organization	Yes or No	Question 6 Comment
different meaning and purpose. **The PTCMD allows the Planning Coordinator to tailor the calculation of PTC to its specific reliability objectives.**		
SERC Planning Standards Subcommittee	No	While we agree with the PTC definition we recommend that the phrase “implementation of a method” in the PTCID definition be replaced with the term “methodology” and the name of the document be changed to “Planning Transfer Capability Methodology Document (PTCMD).”
Response: The SDT agrees with your comment and has modified the definition. The definition now reads “A document that describes the process for calculating Planning Transfer Capability (PTC).”		
Midwest ISO Stakeholder Standards Collaborators	No	There is no need to create the term Planning Transfer Capability (PTC). Transfer Capability is a well understood long standing NERC defined term and should be used in its place. Furthermore, the proposed definition is not consistent with the Transfer Capability or Total Transfer Capability definitions.
Response: The SDT believes the PTC term is necessary to avoid confusion with other forms of transfer capability (i.e. TTC and ATC) that have a different meaning and purpose. The SDT revised the definition of PTC to eliminate the language that duplicated the definition of transfer capability.		
California ISO	Yes	
Duke Energy	Yes	

7. The proposed purpose statement in the draft standard is:

To ensure that Planning Coordinators calculate Planning Transfer Capabilities using an established method such that those Transfer Capabilities can be used effectively in the reliable planning of the Bulk Electric System (BES).

Do you agree with this purpose? If not, please identify to whom the standard should apply.

Summary Consideration: Several of the commenters indicated that the term PTC is unnecessary and proposed that PTC could also be replaced in the Purpose Statement with "Transfer Capability in the planning horizon". The SDT retained the definition of PTC and therefore included the term within the Purpose Statement. The term PTC is necessary to avoid any confusion with other forms of transfer capability (i.e., TTC and ATC) that have different meanings and purposes.

A couple commenters questioned the meaning of the phrase, ". . . used effectively in the reliable planning of the BES." The SDT modified the Purpose Statement to be more succinct - it now reads "To ensure that Planning Coordinators calculate Planning Transfer Capabilities using an established method such that those forecasts of Transfer Capabilities are available for the reliable planning of the Bulk Electric System (BES)."

Organization	Yes or No	Question 7 Comment
Bonneville Power Administration	No	It is unclear what the difference is between the purpose statement of the proposed FAC-013-2 and the purpose statements of FAC-010-2 and FAC-014-2. The purpose statements seem to be identical. BPA asks for clarification regarding the need for this proposed standard. For reference the purpose statement of FAC-010-2 reads as follows:"To ensure that System Operating Limits (SOLs) used in the reliable planning ofthe Bulk Electric System (BES) are determined based on an established methodology or methodologies."The purpose statement of FAC-014-2 reads as follows: "To ensure that System Operation Limits (SOLs) used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies."
Response: There is no relationship between the FAC-010/FAC-14 and FAC-013. FAC-010/FAC-14 deal with calculation and communication of SOLs and IROLs based on specific criteria contained in the standards. FAC-013 only requires calculation of PTCs according to the Planning Coordinator's PTCID (now called the PTCMD in the second draft of the standard), which is based on the Planning Coordinator's criteria. For instance, PTCs may be calculated between areas where no SOLs are established. PTCs are calculated to enhance the Planning Coordinator's understanding of system behavior not to establish system operating limits. The SDT believes the PTC term is necessary to avoid confusion with other forms of transfer capability (i.e. TTC and ATC) that have a different meaning and purpose.		
Midwest ISO Stakeholder	No	Planning Transfer Capabilities should be replaced with Transfer Capabilities. As an option, the purpose

Organization	Yes or No	Question 7 Comment
Standards Collaborators		statement could refer to the Transfer Capabilities in the planning horizon.
Response: The SDT has decided to keep the definition of PTC and therefore has included this term within the Purpose statement. The SDT believes the PTC term is necessary to avoid confusion with other forms of transfer capability (i.e. TTC and ATC) that have a different meaning and purpose. Note that the SDT did revise the definition of PTC – the revised definition eliminates the language that duplicated the definition of transfer capability.		
Xcel Energy	No	Planning Transfer Capability should be replaced with Transfer Capabilities. As an option, the purpose statement could refer to the Transfer Capabilities in the planning horizon.
Response: The SDT has decided to keep the definition of PTC and therefore has included this term within the Purpose statement. The SDT believes the PTC term is necessary to avoid confusion with other forms of transfer capability (i.e. TTC and ATC) that have a different meaning and purpose. Note that the SDT did revise the definition of PTC – the revised definition eliminates the language that duplicated the definition of transfer capability.		
Ameren	No	Please see our comments to question 6.
Response: Please see the response to your comments on question 6. **The SDT believes the PTC term is necessary to avoid confusion with other forms of transfer capability (i.e. TTC and ATC) that have different meanings and purposes.** **The PTCMD (previously called the PTCID) allows the Planning Coordinator to tailor the calculation of PTC to its specific reliability objectives.**		
PJM Interconnection	No	Revised purpose statement: To ensure that Planning Coordinators use an established method for effective, reliable planning of the Bulk Electric System (BES). Note: This methodology does not need to involve the calculation of transfer capability in the planning horizon
Response: The SDT believes there is a necessity for the calculation of planning transfer capability beyond 13 months. The SDT also believes that the proposed Purpose statement is too generic.		
Manitoba Hydro	No	The proposed purpose is unclear. What does 'used effectively in the reliable planning of the Bulk Electric System (BES)' mean?The purpose statement should simply be: To ensure that Planning Coordinators calculate Planning Transfer Capabilities using an established method. Also, if FAC-012-1 and FAC-013-1 are combined, the purpose should include a statement such as "and distribute the PTCs to the entities that have a reliability related requirement for them".
Response: The SDT has reworded the purpose to be more succinct. The purpose statement now reads "To ensure that Planning Coordinators calculate Planning Transfer Capabilities using an established method such that those forecasts of Transfer Capabilities are available for the reliable planning of the Bulk Electric System (BES)." **There are requirements for distribution of PTC's but the SDT does not believe it is necessary to specifically include it in the purpose statement.**		

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 7 Comment</th></tr>
<tr><td>Duke Energy</td><td>No</td><td>The Purpose should be reworded to clearly state that the objective of this standard is not to simply determine transfer capabilities in the planning timeframe, but to assess the future reliability of the system. Suggested rewording: “To ensure that Planning Coordinators use an established methodology to assess whether sufficient transmission system capacity is available to support reliable operation of the Bulk Power System in the planning horizon.”</td></tr>
<tr><td colspan="3">Response: The SDT has decided to keep the definition of PTC and therefore has included this term within the Purpose statement. The SDT believes the PTC term is necessary to avoid confusion with other forms of transfer capability (i.e. TTC and ATC) that have a different meaning and purpose.

The draft standard was not intended to address assessments but only address the development of the PCs methodology to calculate PTCs and share these PTCs with the necessary entities.</td></tr>
<tr><td>Independent Electricity System Operator</td><td>No</td><td>We do not support the word “Planning” before “Transfer Capabilities” for reasons as indicated under Q6, above. Words such as “Planning Coordinators and “reliable planning” already suffice to put the Transfer Capabilities in the proper time horizon perspective.</td></tr>
<tr><td colspan="3">Response: The SDT has decided to keep the definition of PTC and therefore has included this term within the Purpose statement. The SDT believes the PTC term is necessary to avoid confusion with other forms of transfer capability (i.e. TTC and ATC) that have a different meaning and purpose. Note that the team did revise the definition of PTC in support of stakeholder suggestions, and the revised definition eliminates the language that duplicated the definition of transfer capability.</td></tr>
<tr><td>IRC Standards Review Committee</td><td>No</td><td>We do not support the word “Planning” before “Transfer Capabilities” for reasons as indicated under Q6, above. Words such as “Planning Coordinators and “reliable planning” already suffice to put the Transfer Capabilities in the proper time horizon perspective.Note that CAISO does not sign on to this specific comment.</td></tr>
<tr><td colspan="3">Response: The SDT has decided to keep the definition of PTC and therefore has included this term within the Purpose statement. The SDT believes the PTC term is necessary to avoid confusion with other forms of transfer capability (i.e. TTC and ATC) that have a different meaning and purpose. Note that the team did revise the definition of PTC in support of stakeholder suggestions, and the revised definition eliminates the language that duplicated the definition of transfer capability.</td></tr>
<tr><td>Northeast Power Coordinating Council</td><td>No</td><td>We do not support the word “Planning” before “Transfer Capabilities” for reasons as indicated in Question 6 preceding. Words such as "Planning Coordinators" and “reliable planning” suffice to put the Transfer Capabilities in the proper time horizon perspective.</td></tr>
<tr><td colspan="3">Response: The SDT has decided to keep the definition of PTC and therefore has included this term within the Purpose statement. The SDT believes the PTC term is necessary to avoid confusion with other forms of transfer capability (i.e. TTC and ATC) that have a different meaning and purpose. Note that the team did revise the definition of PTC in support of stakeholder suggestions, and the revised definition eliminates the language that duplicated</td></tr>
</table>

Organization	Yes or No	Question 7 Comment
the definition of transfer capability.		
Southern Company Transmission	Yes	Southern agrees with NERC's proposed purpose statement in that Transfer Capabilities should be calculated using an established method and used effectively for the reliable planning of the Bulk Electric System. However, Southern does not believe that NERC's proposed FAC-13-2 addresses this purpose statement. Southern does not believe there are currently any established methods for which Transfer Capabilities are calculated beyond the 13 month timeframe. The existing MOD Reliability Standards (MOD-28-1, MOD-29-1, and MOD-30-2) provide for the calculation of Transfer Capabilities in the operating horizon only (i.e. up to 13 months). FERC's directive in Order 729 was to develop modifications to FAC-12-1 and FAC-13-1 to comply with the relevant directives of Order No. 693, in which, NERC was directed to modify FAC-12-1 to provide a framework for calculating transfer capability. Southern believes NERC has fully addressed this framework in regards to the operating horizon with the MOD Reliability Standards approved within FERC Order 729. As such, Southern recommends that existing reliability standards (i.e. FAC-12-1) be modified or new reliability standards be created to provide a framework for the calculation of Transfer Capabilities beyond 13 months.
Response: The SDT thanks you for your affirmative response and clarifying comment. The SDT has modified the draft standard to provide a framework for the calculation of PTC for the time period beyond 13 months. The SDT has also modified the Purpose Statement to now read "To ensure that Planning Coordinators calculate Planning Transfer Capabilities using an established method such that those forecasts of Transfer Capabilities are available for the reliable planning of the Bulk Electric System (BES)."		
California ISO	Yes	
FirstEnergy	Yes	
Georgia Transmission Corporation	Yes	

8. The draft standard proposes to merge FAC-012 and FAC-013. Do you agree with this approach? If not, please suggest an alternate approach.

Summary Consideration: One commenter questioned the need for FAC-013-2 and instead proposed modifying FAC-010-2 and FAC-014-2 to cover the necessary requirements. There is no relationship between FAC-010-2/FAC-014-2 and FAC-013. FAC-010-2/FAC-014-2 deal with calculation and communication of SOLs and IROLs based on specific criteria contained in the standards while FAC-013-2 requires calculation of PTCs according to the Planning Coordinator's PTCID (now called the PTCMD in the second draft of the standard), which are based on the PC's own set of criteria. A PTC could be calculated between areas where no SOL has been established - PTCs are calculated to enhance the Planning Coordinator's understanding of the system behavior and not to establish operating limits.

Another commenter stated that they did not disagreement with merging FAC-012 and FAC-013 unless a single method of calculating PTCs beyond 13 months was approved. The SDT does not believe identifying a single method would be appropriate. The draft standard FAC-013-2 provides flexibility for Planning Coordinators to evaluate PTCs based on the needs and behavior of the Planning Coordinator's area of responsibility.

Organization	Yes or No	Question 8 Comment
Bonneville Power Administration	No	BPA proposes to retire FAC-012 and FAC-013 and instead modify FAC-010-2, and FAC-014-2 to respond to FERC's directives in Order 693 and Order 729. This will avoid the appearance of duplication and provide consistency between these standards.
Response: There is no relationship between the FAC-010/FAC-14 and FAC-013. FAC-010/FAC-14 deal with calculation and communication of SOLs and IROLs based on specific criteria contained in the standards. FAC-013 only requires calculation of PTCs according to the Planning Coordinator's PTCID (now called the PTCMD in the second draft of the standard), which is based on the Planning Coordinator's criteria. For instance, a PTC may be calculated between areas where no SOL is established. PTCs are calculated to enhance the Planning Coordinator's understanding of system behavior, not to establish system operating limits. The SDT believes the PTC term is necessary to avoid confusion with other forms of transfer capability (i.e. TTC and ATC) that have different meanings and purposes.		
Manitoba Hydro	No	Manitoba Hydro strongly suggests that the Standard Drafting Team revert back to FAC-012. With some minor modifications to the current FAC-012, a clear and adequate standard could be established. By dropping the reference to the RC in R1 & R4 & M1 & M4 & D, R2 and M2 the current FAC-012 would be applicable only to the PA (not the PA and the RC). Requirement R1 in FAC-012 lists some important items that should be included in a transfer capability methodology. These items are not included in the proposed FAC-013-2 standard. There is nothing in the proposed FAC-013-2 standard that makes it superior to the current FAC-012 standard.

Organization	Yes or No	Question 8 Comment
Response: The SDT believes that the revised standard preserves the important requirements from FAC-012 as you have suggested and also addresses the FERC directives.		
Southern Company Transmission	No	Southern does not support merging FAC-12 and FAC-13 unless a single method for calculating Transfer Capabilities beyond 13 months is approved. FAC-13-1 is a FERC approved standard that requires either the reliability coordinator or the planning authority to calculate transfer capabilities based on an established methodology and provide those transfer capabilities to its transmission operators, transmission service providers and planning authorities within the reliability coordinator's area. In FERC's Order 729, the commission stated that the responsibilities of FAC-12 and FAC-13 would be appropriately assigned to the Planning Coordinator and not the reliability coordinator. FAC-13 is simply a standard by which Transfer Capabilities calculated by a Planning Coordinator should be communicated to the Transmission Operator and Transmission Service Provider. FAC-13 does not prescribe how to calculate these Transfer Capabilities. As previously stated, Southern does not believe that there are established methodologies that provide the framework for calculating Transfer Capabilities beyond 13 months. Southern recommends that either FAC-12 be modified to provide the framework for a single methodology used for calculating Transfer Capabilities beyond 13 months or additional standards be created to provide such frameworks similar to those prescribed in the MOD Reliability Standards (MOD-28-1, MOD-29-1, and MOD-30-2). Additionally, Southern would not support the modification of MOD-28-1, MOD-29-1, or MOD-30-2 in order to provide this framework beyond 13 months.
Response: The SDT is not saying that there are present methodologies for calculating PTCs beyond 13 months. The purpose of this draft standard is to mandate that PCs develop these methodologies. **The SDT does not believe that identifying a single method would be appropriate. FAC-013 provides flexibility for Planning Coordinators to calculate PTCs based on the needs and behavior of their area of responsibility, but the Planning Coordinator must document the method in its PTCMD.**		
Georgia Transmission Corporation	Yes	While GTC agrees that the draft standard should merge FAC-012 and FAC-013, the SAR's Detailed Description says "This SAR proposes to retire FAC-012-1, and modify FAC-013-1." How will this inconsistency be explained?
Response: The new FAC-013-2 will be a revision of FAC-013-1 which incorporates the necessary elements of FAC-012-1 to develop an effective standard addressing PTCs used in the planning horizon.		
Ameren	Yes	
California ISO	Yes	
Duke Energy	Yes	

Organization	Yes or No	Question 8 Comment
FirstEnergy	Yes	
Independent Electricity System Operator	Yes	
IRC Standards Review Committee	Yes	
Midwest ISO Stakeholder Standards Collaborators	Yes	
Northeast Power Coordinating Council	Yes	
PJM Interconnection	Yes	
SERC Planning Standards Subcommittee	Yes	
Xcel Energy	Yes	

9. Does the draft standard adequately address the applicable FERC directives (located in the SAR)? If not, please identify what else is needed.

Summary Consideration: Several of the commenters did not feel that the draft standard addressed FERC concerns with data input and modeling assumptions. The SDT modified the draft standard (Requirement R1) to provide a framework for the PTC methodology including data inputs and modeling assumptions.

A couple of the commenters indicated that Requirements R2 and R3 should be merged. The SDT agreed and merged the requirements.

A few of the commenters indicated that the draft standard as written could preclude some entities access to the PTCs. The SDT modified the draft standard to allow any entity with a reliability related need access to the PTCMD (previously called the PTCID) and PTCs.

Organization	Yes or No	Question 9 Comment
IRC Standards Review Committee	No	(1) Requirement R1 stipulates the information that must be provided in the TCID for planning, and identifies the need to explain and justify any differences in the method used that are not consistent with the method selected by the Transmission Operator and described in the associated Transmission Service Provider's Available Transfer Capability Implementation Document (ATCID). We support this requirement but do not think that the requirement as written is sufficient to address the FERC's concerns that:"....FAC-012-1 merely required the documentation of a transfer capability methodology without providing a framework for that methodology including data inputs and modeling assumptions".We understand the Requirement R1 is written to achieve consistency with the pertinent MOD standard (MOD-028 or MOD-029), but it is not clear to us that in the two related standards, the conditions stipulated in the FERC Order in terms of data input and modeling assumption are fully met. We suggest the SDT to review both the draft FAC-013 and the approved MOD standards to ascertain that the FERC's concerns are fully addressed. (2) We suggest R2 and R3 be combined by "Each Planning Coordinator shall make available its current [P]TCID to all of the following entities, and notify these entities before implementing a new or revised [P]TCID. (The [P] indicates our proposal to remove the word "Planning" for the two terms.) (3) We believe the Transmission Planner should be added to Part 2.1. (4) R5 as written may prohibit some entities that have a reliability-related need to obtain the calculated Transfer Capabilities, for example, the Reliability Coordinators. Also, the TCID need-to-know entities in R2 and the TC need-to-know entities in R5 are not consistent. We suggest to make them the same, with consideration of including the RCs in the list.

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 9 Comment</th></tr>
<tr><td colspan="3">Response: The SDT has modified the standard (Requirement R1) to provide a framework for the PTC methodology including data inputs and modeling assumptions to address FERC concerns.

The SDT agrees with your suggestion to combine R2 and R3 and they have been combined in this revised version. Note that the SDT did not remove the word “Planning” as proposed. For consistency, the word was retained in the definition of PTC, PTCID (now called PTCMD in the second draft of the standard), and in the requirements to maintain clarity between transfer capability used in this standard and the various forms of transfer capability (ATC, TTC) used in other standards.

The Transmission Planner was included in the Requirement 2 (Part 2.4) and is still included in Part 2.2 in the second version of the proposed standard.

The standard has been modified to allow those entities with a reliability-related need access to the PTCMD and PTC’s – this would include RCs</td></tr>
<tr><td>Independent Electricity System Operator</td><td>No</td><td>(1) We suggest R2 and R3 be combined by “Each Planning Coordinator shall make available its current PTCID to all of the following entities, and notify these entities before implementing a new or revised TCID:
(2) We believe the Transmission Planner should be added to Part 2.1.
(3) R5 as written may preclude some entities that have a reliability-related need to obtain the calculated Transfer Capabilities from receiving them, for example, the Reliability Coordinators. Also, the TCID need-to-now entities in R2 and the TC need-to-know entities in R5 are not consistent. We suggest to make them the same, with consideration of including the RCs in the list.</td></tr>
<tr><td colspan="3">Response: The SDT agrees with your suggestion to combine R2 and R3 and they have been combined in the second version of the proposed standard.

The Transmission Planner was included in the Requirement R2 (Part 2.4) and is still included in the second draft of the proposed standard. (Requirement R2, Part 2.2)

The standard has been modified to allow those entities with a reliability-related need access to the PTCMD and PTC’s – this would include RCs.</td></tr>
<tr><td>Northeast Power Coordinating Council</td><td>No</td><td>(1) We suggest R2 and R3 be combined by “Each Planning Coordinator shall make available its current TCID to all of the following entities, and notify these entities before implementing a new or revised TCID: ...

(2) Transmission Planner should be added to Part 2.1.

(3) R5 as written may prohibit some entities that have a reliability-related need to obtain the calculated Transfer Capabilities, for example, the Reliability Coordinators. Also, the TCID need-to-know entities in R2 and the TC need-to-know entities in R5 are not consistent. We suggest to make them the same, and include RC in the list.</td></tr>
<tr><td colspan="3">Response The SDT agrees with your suggestion to combine R2 and R3 and they have been combined in the second version of the proposed standard.

The Transmission Planner was included in the Requirement (R2.4) and is still included in this revised version of the proposed standard.

The standard has been modified to allow those entities with a reliability-related need access to the PTCMD and PTC’s – this would include RCs.</td></tr>
</table>

Organization	Yes or No	Question 9 Comment
Southern Company Transmission	No	In FERC Order 693, the commission directed NERC to modify FAC-12 to, at a minimum, provide a framework for the transfer capability calculation methodology, including data inputs and modeling assumptions. Southern believes that this directive has been fully addressed for the timeframe of 1 hour through 13 months with the MOD Reliability Standards approved within FERC Order 729. The commission stated in FERC Order 729 that calculation of transfer capabilities for the planning horizon (years one through five) had not been addressed by the MOD Reliability Standards and gave additional directives that FAC-12 and FAC-13 be modified to comply with the original directives of FERC Order 693. The primary requirements of the draft standard require the Planning Coordinator to: 1) define the interfaces in which Transfer Capabilities are calculated, 2) explain why the method used to calculate these Transfer Capabilities differ from the method selected by the Transmission Operator in Transmission Service Provider's ATCID, and 3) share the calculated Transfer Capabilities with specified entities. However, the draft standard does not provide the framework for how the Transfer Capabilities should be calculated; and, as previously stated, Southern does not believe that there are established methodologies that provide the framework for calculating Transfer Capabilities beyond 13 months. Therefore, Southern contends that the draft standard does not meet the directive of providing the framework for calculating Transfer Capabilities beyond 13 months.
Response: The SDT has modified the standard to provide a framework for the PTC methodology including data inputs and modeling assumptions to address FERC concerns – see revised Requirement R1.		
Manitoba Hydro	No	In order 729 point 279 the following is stated: 'The Commission expressed concern the FAC-012-1 merely required the documentation of a transfer capability methodology without providing a framework for that methodology including data inputs and modeling assumptions.'Where in the draft standard is it required that the PTCID provide data inputs and modeling assumptions?
Response: The SDT has modified the standard to provide a framework for the PTC methodology including data inputs and modeling assumptions to address FERC concerns. Requirement R1 establishes the framework.		
California ISO	No	In support of the SRC comments related to question 9, we suggest the SDT to review both the draft FAC-013-2 and the approved MOD Standards (i.e., MOD-028 or MOD-029) to ascertain that FERC's concerns regarding data input and modeling assumptions are fully addressed. We also support the SRC comment to include the RC in R5.
Response: SDT has added data and modeling details to Requirement R1 to establish a framework and consistency for the PTC methodology. **The RC has access to the information under Requirement R6 by demonstrating a reliability related need.**		

Organization	Yes or No	Question 9 Comment
Ameren	No	Please see our response to question 1.
Response: The SDT has added data and modeling details to R1 to establish a framework and consistency for the PTC methodology but still allowing for flexibility for individual Planning Coordinators.		
FirstEnergy	No	The draft standard does not appear to include a requirement "that the criteria used to calculate planning capabilities for use in planning be identical to the criteria used to calculate available transfer capability and to operate the system."
Response: The standard has been revised and Requirement R1 Part 1.4 now specifies that this criteria must be included.		
Midwest ISO Stakeholder Standards Collaborators	No	The draft standard does not provide much detail around the data inputs and modeling assumptions requirements that Order 693 directed.
Response: The SDT has added data and modeling details to Requirement R1 to establish a framework and consistency for the PTC methodology.		
Xcel Energy	No	The draft standard does not provide much detail around the data inputs and modeling assumptions requirements that Order 693 directed.
Response: The SDT has added data and modeling details to Requirement R1 to establish a framework and consistency for the PTC methodology.		
SERC Planning Standards Subcommittee	No	The SAR goes beyond what was identified as "concerns" by FERC, see response to Question 1.
Response: The SDT has added data and modeling details to R1 to establish a framework and consistency for the PTC methodology but still allowing for flexibility for individual Planning Coordinators.		
Duke Energy	Yes	
Georgia Transmission Corporation	Yes	

10. Do you agree with the measures in the standard (section C)? If not, please state specific reasons why not.

Summary Consideration: Several of the commenters indicated that Requirement R4 and Measure M4 were not properly aligned. The SDT reviewed and modified all of the Requirements and Measures ensuring the proper alignment.

A few commenters indicated that the draft standard was too prescriptive concerning the periods/seasons to be studied. The SDT modified the prescriptive language from M4 related to periods/seasons. The revised draft standard affords the Planning Coordinator the flexibility to determine the period/seasons to be studied.

Organization	Yes or No	Question 10 Comment
IRC Standards Review Committee	No	(1) M4 conveys different evidence requirements than the what R4 requires. R4 asks for annual verification of each of the four seasons' Transfer Capabilities. M4 asks for evidence of verification of the Summer and Winter TCs only, but for once every 3 months. They are very different that what's stipulated in the requirement. We suggest M4 be revised to:"Each Planning Coordinator have evidence that it verified, and if necessary recalculated, its TCs consistent with its TCID for each season (Spring, Summer, Fall, and Winter) for years two through five at least once each calendar year.Note that CAISO does not sign on to this specific comment. CAISO is concerned that the Requirement R4 is excessive. Requiring the PC to conduct planning assessments for the Summer and Winter seasons for each calendar year from years two through five, as in current practice across the continent, would suffice. Regardless, there is an inconsistency between Requirement R4 and Measure M4. (2) Some Measure may need to be revised depending on the SDT's response to our comments under Q9.
Response: The SDT has modified Requirement R4 and Measure M4 to better align with one another and to provide consistency. References to specific seasons were omitted from both the requirement and the measure. **The SDT has revised the standard. In this process the SDT has reviewed the measures and modified them as necessary to better align with the Requirements.**		
Independent Electricity System Operator	No	(1) M4 conveys different evidence requirements than what R4 requires. R4 asks for annual verification of each of the four seasons' Transfer Capabilities. M4 asks for evidence of verification of the Summer and Winter TCs only, but for once every 3 months. They are very different that what's stipulated in the requirement. We suggest M4 be revised to:"Each Planning Coordinator shall have evidence that it verified, and if necessary recalculated, its TCs consistent with its TCID for each season (Spring, Summer, Fall, and Winter) for years two through five at least once each calendar year.

Organization	Yes or No	Question 10 Comment
		(2) Some Measure may need to be revised depending on the SDT's response to our comments under Q9.
Response: The SDT has modified Requirement R4 and Measure M4 to better align with one another and to provide consistency. References to specific seasons were omitted from both the requirement and the measure. The SDT has revised the standard. In this process the SDT has reviewed the measures and modified them as necessary to better align with the Requirements.		
Northeast Power Coordinating Council	No	(1) M4 conveys different evidence requirements than what R4 requires. R4 asks for annual verification of each of the four seasons' Transfer Capabilities. M4 asks for evidence of verification of the Summer and Winter TCs only, but once every 3 months. They are very different from what's stipulated in the requirement. We suggest M4 be revised to:"Each Planning Coordinator have evidence that it verified, and if necessary recalculated, its TCs consistent with its TCID for each season (Spring, Summer, Fall, and Winter) for years two through five at least once each calendar year. (2) Some Measures may need to be revised depending on the SDT's response to our comments to Question 9.
Response: The SDT has modified Requirement R4 and Measure M4 to better align with one another and to provide consistency. References to specific seasons were omitted from both the requirement and the measure. The SDT has revised the standard. In this process the SDT has reviewed the measures and modified them as necessary to better align with the Requirements.		
Bonneville Power Administration	No	Comment #1: R4 does not line up with M4. R4 requires PTCs for spring, summer, fall, and winter while M4 only requires PTCs for each winter and summer. Also R4 requires PTCs to be verified and recalculated, if necessary, at least once each calendar year while M4 requires verification and recalculation of PTCs, if necessary, every three months. These are inconsistent. o BPA proposes the following modification to R4: "Each Planning Coordinator shall verify, and if necessary, recalculate PTCs consistent with its PTCID at least once a year for at least the most limiting season (spring, summer, fall, or winter) for years two through five." o BPA proposes the following language for M4: "Each Planning Coordinator have evidence that it verified, and if necessary, recalculated, its PTCs consistent with its PTCID at least once a year for the most limiting season (spring, summer, fall, or winter) for years two through five." Comment #2: R5 does not line up with M5. R5 requires the Planning Coordinator to make available PTC values to the entities listed, while M4 requires Planning Coordinators to make available the PTCID to those

Organization	Yes or No	Question 10 Comment
		entities. The VSL indicates the Planning Coordinator makes available the PTCs. Is this correct?
Response: The SDT has modified Requirement R4 and Measure M4 to better align with one another and to provide consistency. References to specific seasons were omitted from both the requirement and the measure. **The SDT agrees that the Measure M5 should reference PTC's and not PTCMD. This has been corrected.** **The standard has been modified to allow those entities with a reliability-related need access to the PTCMD and PTCs. The VSLs have been modified to be consistent with the modified requirements.**		
California ISO	No	M4 conveys different evidence requirements compared to what R4 requires. We suggest that R4 and M4 provide some flexibility to the Planning Coordinator to study and verify the conditions that are appropriate for the study area, rather than to require for all four seasons. For example, a peak and off-peak study in R4 may be appropriate for a study area. Similar flexibility in the language should be included in M4.Suggested wording for M4 would be: "Each Planning Coordinator have evidence that it verified, and if necessary recalculated, its PTCs consistent with its PTCID for relevant study scenarios as appropriate for the study area."
Response: The SDT believes that the modifications made to the Requirements and Measures in this version of the draft standard affords the flexibility you have requested. References to specific seasons were omitted from both Requirement R4 and the Measure M4.		
Manitoba Hydro	No	M4: This measure should only require the PC have evidence that it verified , and if necessary recalculated, its PTCs consistent with its PTCID for each winter and summer season for years two through five at least once a year. In R4 is it stated '...at least once each calendar year.'. M5: PTCID should be changed to PTCs. Also, since the PC's PTCs are in the Planning Horizon, there is no need to make them available within a time frame as short as ten calendar days. One month would be a more appropriate time frame.
Response: The SDT has modified Requirement R4 and Measure M4 to better align with each other and to provide consistency. References to specific seasons were omitted from both the requirement and the measure. **The SDT has revised the standard. In this process the SDT has reviewed the measures and modified them as necessary to better align with the Requirements.** **The reference to PTCID in Measure M5 has been changed to PTCs.** **The SDT has modified the Requirement to allow for thirty days.**		
Ameren	No	Measure 4 is not consistent with the requirement. The requirement requires recalculation once a calendar year and the measure attempts to require recalculation once a quarter. Do we need spring and fall PTC (R4)

Organization	Yes or No	Question 10 Comment
		when the vales more appropriate for planning would be summer and winter as included in M4.
Response: The SDT has modified Requirement R4 and Measure M4 to better align with one another and to provide consistency. **The Requirements and Measures have been modified to afford the Planning Coordinator the flexibility to determine the seasons to be studied.**		
Midwest ISO Stakeholder Standards Collaborators	No	Measure 4 is not consistent with the requirement. The requirement requires recalculation once a calendar year and the measure attempts to require recalculation once a quarter.
Response: The SDT has modified Requirement R4 and Measure M4 to better align with one another and to provide consistency. **The SDT has revised the standard. In this process the SDT has reviewed the measures and modified them as necessary to better align with the Requirements.**		
Georgia Transmission Corporation	No	Requirement 4 of the draft standard states, “Each Planning Coordinator shall verify, and if necessary recalculate, PTCs consistent with its PTCID for each season (Spring, Summer, Fall, and Winter) for years two through five at least once each calendar year.” However, Measurement 4 states, “Each Planning Coordinator have evidence that it verified, and if necessary recalculated, its PTCs consistent with its PTCID for each winter and summer season for years two through five at least once every three months.” Why is the measurement for each winter and summer season when Requirement 4 specified PTCs for spring, summer, fall, and winter?
Response: The SDT has modified Requirement R4 and Measure M4 to better align with one another and to provide consistency. References to specific seasons were omitted from both the requirement and the measure. **The SDT has revised the standard. In this process the SDT has reviewed the measures and modified them as necessary to better align with the Requirements.**		
Duke Energy	No	Requirement R4 is much too prescriptive and we propose changes to it in our response to Question # 13 below. Measure M4 should be revised to match the revised requirement. Likewise Requirement R5 has far too tight a timeframe to communicate verified or recalculated transfer capabilities. Since these transfer capabilities are years in the future, 45 days should be allowed to communicate them instead of 10 days.
Response: The SDT has modified Measure M4 to better align with R4 and to provide consistency References to specific seasons were omitted from both the requirement and the measure. **The SDT has revised the standard. In this process the SDT has reviewed the measures and modified them as necessary to better align with the Requirements.** **The SDT believes that the modifications made to the Requirements and Measures in this version of the draft standard affords the flexibility you have requested. The team did modify R5 to add more time, but changed the due date from 10 calendar days to 30 calendar days.**		

Organization	Yes or No	Question 10 Comment
Southern Company Transmission	No	Southern disagrees with measure M4 in that verification, or possible recalculation of PTCs, should be performed any more frequent than once a year. Southern does not believe that there is a reliability need to calculate PTCs on a quarterly basis for PTCs to be utilized beyond the 13 month horizon. Additionally, Southern does not believe there is a reliability need to calculate seasonal PTCs; and therefore, disagrees that each winter and summer season for years two through five should be verified, or recalculated at least once every three months.
Response: The SDT has modified Requirement R4 and Measure M4 to better align with one another and to provide consistency. References to specific seasons were omitted from both the requirement and the measure. **The SDT has revised the standard. In this process the SDT has reviewed the measures and modified them as necessary to better align with the Requirements.**		
FirstEnergy	No	The measures will need to be adjusted for the suggested changes in our response to item 9 above.
Response: The SDT has revised the standard. In this process the SDT has reviewed the measures and modified them as necessary to better align with the Requirements.		
SERC Planning Standards Subcommittee	No	We agree with the MISO comment that Measure 4 is not consistent with the requirement. The requirement requires recalculation once a calendar year and the measure attempts to require recalculation once a quarter.
Response: The SDT has modified Requirement R4 and Measure M4 to better align with one another and to provide consistency.		
Xcel Energy	No	We believe it is premature to establish and review measures until the refinement of requirements is closer to completion
Response: The SDT thanks you for your clarifying comment.		

11. Do you agree with the compliance elements in the standard (Violation Risk Factors, Time Horizons, Violation Severity Levels, and the remainder of section D)? If not, please state specific reasons why not.

Summary Consideration: Several of the commenters felt that the retention period for Requirements R2 and R3 may not be sufficient and that these requirements should be combined as suggested earlier. The SDT merged the two Requirements into one Requirement and agrees with the comment concerning the retention period. The SDT modified the retention period, changed the retention for the revised R2 to require retention of evidence since the last audit to correct any deficiency.

Several commenters also questioned the VRF level set for the Requirements. The SDT reviewed all of the VRFs associated with the Requirements and adjusted them accordingly, lowering two of the VRFs from a "Medium" VRF to a "Lower" VRF level.

Many commenters indicated that the VSLs should have more than one level for determining non-compliance. The SDT agrees in concept with the commenters and modified all of the VSLs in the new draft of the draft standard.

A couple of commenters indicated that there should only be one VSL for Requirement R3 and Requirement R5. The SDT disagrees with the commenters and added more gradated VSLs. Since the requirements apply in a planning timeframe, there should be an allowance for being late with notifications.

Organization	Yes or No	Question 11 Comment
Northeast Power Coordinating Council	No	(1) The retention period for R2 and R3 (or combined as suggested in Question 9) may not provide the evidence needed if there has not been a change to the TCID in the past 24 months. Suggest to change the retention period to be the same as R1. (2) R2: The wording for Lower can be interpreted to mean that the responsible entity did not comply with the requirement even if it notified all entities before implementing a new TCID. We suggest to reword it to:"The Planning Coordinator notified one or more of the parties specified in R2 of a new or modified TCID, but was late by up to 30 calendar days after its implementation." (3) R5: Unlike its R2 counterpart, timing is not factored into the VSLs. We suggest to add a second condition under each VSL as follows:Lower: The Planning Coordinator made the TCs available to one or more of the entities described in R5, Part 5.2, but was late by up to 30 calendar days after the 10 calendar day target.Moderate: The Planning Coordinator made the TCs available to one or more of the entities described in R5, Part 5.2, but was late more than 30 calendar days after the 10 calendar day target.High: The Planning Coordinator made the TCs available to one or more of the entities described in R5, Part 5.1, but was late by up to 30 calendar days after the 10 calendar day target.Severe: The Planning Coordinator made the TCs available to one or more of the entities described in R5, Part 5.1, but was late more than 30 calendar days after the 10 calendar day target. If the above suggestions are not adopted, then we suggest to add the

Organization	Yes or No	Question 11 Comment
		condition "within 10 calendar days" at the end of each VSL. For example, the Lower VSL will read:"The Planning Coordinator made the TCs available to some, but not all, of the entities described in R5, Part 5.2 within 10 calendar days." (4) Some of the VSLs may need to be revised depending on the SDT's response to our comments to Question 9.
Response: 1) The SDT agrees with your comment and has modified the draft standard to indicate that the evidence for the combined R2/R3 must be retained from the last audit. **2) The SDT agrees with your comment regarding the Lower VSL for Requirement R2 and has modified the wording in the second draft of the proposed standard.** **3) & 4) The SDT agrees with your comment in concept and has modified the VSLs.**		
Independent Electricity System Operator	No	(1) The retention period for R2 and R3 (or to be combined as we suggest) may not provide the evidence needed if there has not been a change to the TCID in the past 24 months. Suggest to change the retention period to be the same as R1. (2) R2: For the Lower VSL we suggest the following alternative wording to avoid any possible misinterpretation:"The Planning Coordinator notified one or more of the parties specified in R2 of a new or modified PTCID, but was late by up to 30 calendar days after its implementation. (3) R5: Unlike its R2 counterpart, timing is not factored into the VSLs. We suggest to add a second condition under each VSL as follows:Lower: The Planning Coordinator made the TCs available to one or more of the entities described in R5, Part 5.2, but was late by up to 30 calendar days after the 10 calendar day target.Moderate: The Planning Coordinator made the TCs available to one or more of the entities described in R5, Part 5.2, but was late more than 30 calendar days after the 10 calendar day target.High: The Planning Coordinator made the TCs available to one or more of the entities described in R5, Part 5.1, but was late by up to 30 calendar days after the 10 calendar day target.Moderate: The Planning Coordinator made the TCs available to one or more of the entities described in R5, Part 5.1, but was late more than 30 calendar days after the 10 calendar day target. If the above suggestions are not adopted, then we suggest to add the condition "within 10 calendar days" at the end of each of the VSL. For example, the Lower VSL will read:"The Planning Coordinator made the TCs available to some, but not all, of the entities described in R5, Part 5.2 within 10 calendar days." (4) Some of the VSLs may need to be revised depending on the SDT's response to our comments under Q9.
Response: 1) The SDT agrees with your comment and has modified draft standard to indicate that the evidence for the combined R2/R3 must be retained from the last audit.		

Organization	Yes or No	Question 11 Comment
2) The SDT agrees with your comment regarding the Lower VSL for Requirement R2 and has modified the wording in the second draft of the proposed standard. **3) & 4) The SDT agrees with your comment and has modified the VSLs.**		
IRC Standards Review Committee	No	(1) The retention period for R2 and R3 (or to be combined as we suggest) may not provide the evidence needed if there has not been a change to the TCID in the past 24 months. Suggest to change the retention period to be the same as R1. (2) R2: The wording for Lower can be interpreted to mean that the responsible entity did not comply with the requirement even if it notified all entities before implementing a new TCID. We suggest to reword it to:"The Planning Coordinator notified one or more of the parties specified in R2 of a new or modified PTCID, but was late by up to 30 calendar days after its implementation. (3) R5: Unlike its R2 counterpart, timing is not factored into the VSLs. We suggest to add a second condition under each VSL as follows:Lower: The Planning Coordinator made the TCs available to one or more of the entities described in R5, Part 5.2, but was late by up to 30 calendar days after the 10 calendar day target.Moderate: The Planning Coordinator made the TCs available to one or more of the entities described in R5, Part 5.2, but was late more than 30 calendar days after the 10 calendar day target.High: The Planning Coordinator made the TCs available to one or more of the entities described in R5, Part 5.1, but was late by up to 30 calendar days after the 10 calendar day target.Moderate: The Planning Coordinator made the TCs available to one or more of the entities described in R5, Part 5.1, but was late more than 30 calendar days after the 10 calendar day target. If the above suggestions are not adopted, then we suggest to add the condition "within 10 calendar days" at the end of each of the VSL. For example, the Lower VSL will read:"The Planning Coordinator made the TCs available to some, but not all, of the entities described in R5, Part 5.2 within 10 calendar days." (4) Some of the VSLs may need to be revised depending on the SDT's response to our comments under Q9.
Response: 1) The SDT agrees with your comment and has modified draft standard to indicate that the evidence for the combined R2/R3 must be retained from the last audit. **2) The SDT agrees with your comment regarding the Lower VSL for Requirement R2 and has modified the wording in the second version of the proposed standard.** **3) & 4) The SDT agrees with your comment and has modified the VSLs.**		
Bonneville Power Administration	No	Comment #1: The 1.4 Data Retention requirement mandates that the Planning Coordinator maintain its current ATCID. Was the intent for the Planning Coordinator to maintain its current PTCID? Comment #2: The risk to reliability from not complying with this standard is very low as it addresses the Planning horizon. A severe Violation Severity Level is too high for these standards.

Organization	Yes or No	Question 11 Comment
		Comment #3: BPA proposes the following changes for the VSL's for R1: o Lower VSL: The Planning Coordinator has a PTCID that does not incorporate changes made up to six months ago. o The wording used for High VSL should replace the wording for Moderate VSL. o The wording used for Severe VSL should replace the wording for High VSL. Comment #4: BPA proposes the following changes to R2: o Lower VSL: The Planning Coordinator failed to notify one or more parties specified in R2 of a new or modified PTCID after, but no more than 45 days after its implementation. o Moderate VSL: The Planning Coordinator failed to notify one or more parties specified in R2 of a new or modified PTCID more than 45, but no more than 90 calendar days after its implementation. o High VSL: The Planning Coordinator failed to notify one or more of the parties specified in R2 of a new or modified PTCID more than 90 calendar days following its implementation. Comment #5: BPA proposes that there should be only one VSL for R3 and it should read as follows: o High VSL: The Planning Coordinator failed to make its PTCID available to one of more of the entities described in R3. Comment #6: BPA proposes that there should be only one VSL for R5 and it should read as follows: o High VSL: The Planning Coordinator failed to make the PTCs available to one or more of the entities described in R5, Part 5.2.
Response: 1) The typo in the Data Retention section has been corrected. **2) The SDT agrees with your comment and has set the VRFs to "Lower" in this version of the draft standard.** **3) The SDT has modified the VSLs for Requirement R1 to better reflect the original and revised Requirement R1.** **4) The SDT agrees in concept with your comment concerning the VSLs for Requirement R2 and has modified the VSLs.** **5 & 6) The SDT disagrees and has actually added VSLs. The SDT felt that since this is in the planning timeframe there should be an allowance for being late with notification.**		
Georgia Transmission Corporation	No	R1 and R4 are listed as having Medium Violation Risk Factors. R1 is a documentation requirement; R4 requires calculations 13 months before real time. These requirements should have Lower Violation Risk Factors.
Response: The SDT agrees with your comment and has modified the second version of the draft standard to reflect "Lower" VRF's.		

Organization	Yes or No	Question 11 Comment
SERC Planning Standards Subcommittee	No	R1 and R4 should have a VRF of “Lower”. Calculation of PTCs will not directly lead to BES risk. The second alternative for High VSL for R1 should be graduated from Lower to Severe.
Response: The SDT agrees with your comment and has modified the second version of the draft standard to reflect “Lower” VRF’s.		
Duke Energy	No	Requirement R1 should be a Lower VRF, since it’s a documentation requirement. Also, VSLs should be revised consistent with proposed changes to the requirements.
Response: The SDT agrees with your comment and has modified the second version of the draft standard to reflect “Lower” VRF’s. **The SDT ahs reviewed all of the VSL’s and modified them as necessary to be consistent with revisions to the requirements.**		
Manitoba Hydro	No	The Violation Risk Factors should all be Lower. The Time Horizons are all Planning and as such violating any of the Requirements in this proposed standard will not result in anything more than a low level of risk.Violation Severity Levels:R1: The VSLs refer to times of three months/six months/not more than one year/a year or more whereas Requirement R1 does not refer to any time periods.R2: The VSLs refer to times of 30 calendar days/31-60 calendar days/61-90 calendar days/more than 90 calendar days whereas Requirement R2 does not refer to any time periods.R3: The VSLs are not properly allocated for a binary VSL Requirement.R5: The VSLs do not mention any time periods whereas Requirement R5 states ‘...no later than ten calendar days...’.
Response: The SDT agrees with your comment and has modified the second version of the draft standard to reflect “Lower” VRF’s. **Requirements R1 & R2) The SDT has modified the VSLs to better align with the intent of the requirement taking into account time periods when necessary.** **Requirement R3) The SDT has merged the old Requirement R2 and Requirement R3 together and the VSLs have been modified accordingly.** **Requirement R5) The SDT agrees with your comment and has modified the VSL accordingly.**		
California ISO	No	We request consideration be given to extend the “no later than 10 calendar days” time allowed in R5 and the VSLs for R5 to "no later than 15 calendar days." We suggest the following for R5 VSLs:Lower VSL: The Planning Coordinator made the PTCs available to one or more of the entities described in R5, Part 5.2, after 15 calendar days.Moderate VSL: The Planning Coordinator made the PTCs available to none of the entities described in R5, Part 5.2, within 15 calendar days.High VSL: The Planning Coordinator made the PTCs available to one or more of the entities described in R5, Part 5.1, after 15 calendar days.Severe VSL: The Planning Coordinator made the PTCs available to none of the entities described in R5, Part 5.1 within 15 calendar days.
Response: The SDT agrees with your comment and has modified the draft standard to reflect 30 calendar days **The VSLs have been modified based on calendar days. The SDT feels that notification is extremely important but also believes there should be some**		

Organization	Yes or No	Question 11 Comment
allowance for late notification.		
FirstEnergy	Yes	
Southern Company Transmission	Yes	

12. Are you aware of any conflicts between the proposed standards and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

Summary Consideration: There was only one comment and this was a repeat of an earlier comment.

Organization	Yes or No	Question 12 Comment
California ISO	No	
Duke Energy	No	
FirstEnergy	No	
Georgia Transmission Corporation	No	
IRC Standards Review Committee	No	
Manitoba Hydro	No	
SERC Planning Standards Subcommittee	No	
Southern Company Transmission	No	
PJM Interconnection	Yes	See answers to questions 4 and 5
Response: See response to Question 4 and Question 5.		

13. Please provide any other comments (that you have not already provided in response to the questions above) that you have on the proposed standard.

Summary Consideration: A couple of commenters indicated that the draft standard was too prescriptive as to the frequency of the studies. The SDT agreed with the commenter and modified the requirement to now read "Each Planning Coordinator shall verify, and if necessary recalculate, PTCs consistent with its PTCMD (formerly called the PTCID) for years two through five at least once each year."

A few of the commenters stated that 10 days was not sufficient time for making PTCs available. The SDT agreed with the commenter and modified the draft standard to allow for 30 calendar days.

A couple of commenters indicated that PTCs should be made available to certain entities without being asked. The SDT agreed with the commenter and modified the draft standard to reflect the suggested change.

A couple of the commenters indicated the standard was unclear as to the paths that needed to be studied for PTC calculations. The SDT explained that the Planning Coordinator should be afforded the flexibility to include more or fewer paths as well as define the paths in its PTCMD (formerly called PTCID) if they believe that it is appropriate.

Another commenter indicated that the standard should require coordination of interfaces for the calculation of PTC with other PC's. The SDT explained that requirement to share the information with other entities allowed the entities to review the information and therefore was sufficient coordination.

Organization	Yes or No	Question 13 Comment
Ameren		(1) In R5, PTC should be available to all the entities in R2 without being asked. TOP will be more interested in changes in PTC than changes in PTCID. (2) It is unclesr if PTC to be calculated between TOP areas, or from BA to BA, region to region, or sub-region to sub-refion? The document should require PC to work with TP and TOP to identify necessary interfaces to calculate transfer capabilities for Planning horizon. (3) PTC should be referred to as an acronym in R1.1 when it is used first time as the acronym was used then in R4.

Response: 1) The SDT agrees and has modified this version of the draft standard to reflect your suggestion to make the document available to any entity with a reliability-related need for the information.

2) The SDT believes the Planning Coordinator should be afforded the flexibility to include more or fewer paths in its PTCMD if it believes it appropriate. The requirement to share the PTCMD and the requirement to respond to comments received will afford appropriate input.

3) The SDT agrees and this version of the draft standard reflects your suggested modification.

Organization	Yes or No	Question 13 Comment
Manitoba Hydro		Manitoba Hydro strongly suggests that the Standard Drafting Team refer back to FAC-012. With some minor modifications to the current FAC-012, a clear and adequate standard could be established. By dropping 4.1, the reference to the RC in R1 & R4 & M1 & M4 & D, R2 and M2 the current FAC-012 would be applicable only to the PA (not the PA and the RC). Requirement R1 in FAC-012 lists some important items that should be included in a transfer capability methodology. These items are not included in the proposed FAC-013-2 standard. There is nothing in the proposed FAC-013-2 standard that makes it superior to the current FAC-012 standard.Referring to the proposed FAC-013-2 Standard, R4 requires the PC to complete many detailed studies and verifications. This is unnecessary work in determining planning horizon PTCs. R4 should be changed to 'Each Planning Coordinator shall verify, and if necessary recalculate, PTCs consistent with its PTCID for the Summer and Winter seasons for years two and five at least once each calendar year.' Spring and Fall models are not currently created in the Planning Horizon. Requiring the PC to model and analyze Spring and Fall models in the Planning Horizon seems to be market driven, rather than reliability driven.There are is no requirement that the PCs on either side of an 'interface' coordinate when determining PTCs for the 'interface'. The Effective Date cannot be dependent on another standards' effective date (ie. cannot be dependent are the date that MOD-001-1, MOD-028-1, MOD-029-1 and MOD-030-2 are effective).
Response: The revised standard preserves the important requirements from FAC-012 as suggested. **The SDT agrees with your concerns about scope of work and has modified the requirement to read "Each Planning Coordinator shall verify, and if necessary recalculate, PTCs consistent with its PTCMD for years two through five at least once each calendar year, with no more than 15 months between verifications."** **The SDT believes that sharing the information with the PCs is sufficient coordination as required in the new R2 and R5. FERC has recognized that even in ATC calculations ATC values will not be identical on either side of the interface(s).** **The effective date has been established through FERC Order and is beyond the SDT's control.**		
Georgia Transmission Corporation		Requirement 1.1.1 of the draft standard states, "A list of the interfaces for which the Planning Coordinator determines a Planning Transfer Capability". GTC believes this should be ""A list of ATC Paths for which the Planning Coordinator determines a Planning Transfer Capability." This would be consistent with the definitions of ATC in MOD-001-1 and TTC in MOD-028-1, MOD-029-1, and MOD-030-2. ATC and TTC in the MOD standards are calculated for each ATC Path. Order 729, paragraph 291 states, "In making these revisions, the ERO should consider the development of a methodology for calculation of inter-regional and intra-regional transfer capabilities". Will this FERC request be considered? If so, please identify the part of the draft standard that addresses it.
Response: The SDT believes that Requirement R1 will provide the needed framework for evaluating transfer capability beyond 13 months while ensuring that the Planning Coordinator's need for flexibility is met. The phrase, "A list of the interfaces for which the Planning Coordinator determines a Planning Transfer Capability" was removed from the second draft of the proposed standard.		

Organization	Yes or No	Question 13 Comment
California ISO		We suggest that R4 and M4 provide some flexibility to the Planning Coordinator to evaluate the conditions that are appropriate for the study area, rather than to require all four seasons be evaluated. For example, a peak and off-peak study in R4 may be appropriate for a study area. For R4, where it specifies for years two through five, we request that the SDT consider years two and five, similar to the proposed Requirement 2.1.1 in Draft 5 of the TPL-001-1 Standard that is under development in NERC Project 2006-02. For R5, we ask the SDT to give consideration to extending the timeframe allowed beyond 10 calendar days to 15 calendar days.
Response: The SDT has removed the requirement to study all four seasons and modified the requirement to now read "Each Planning Coordinator shall verify, and if necessary recalculate, PTCs consistent with its PTCMD for years two through five at least once each calendar year, with no more than 15 months between verifications." The SDT feels that studying years 2 through 5 is appropriate. **Requirement R5 has been modified to allow 30 calendar days for making PTCs available.**		
FirstEnergy	Yes	Each requirement shows a time horizon of "Planning", however, this is not a defined horizon. There are two types of planning horizons defined by NERC, "Long-Term Planning" and "Operations Planning". The SDT should clarify the intent is Long-Term Planning.
Response: The definition of PTC clarifies that the time period is beyond 13 months. The time horizons are defined, and the definition of the "Long-Term Planning" time horizon is "a planning horizon of one year or longer"		
Midwest ISO Stakeholder Standards Collaborators	Yes	It is not clear why the document focuses on Transmission Operators and not the traditional way in calculating transfer capabilities such as from BA to BA, region to region, sub-region to sub-region. The document should simply require the PC to identify what necessary interfaces it will calculate transfer capabilities on.R2 and R3 should be combined into a single requirement. R2 in essence requires pre-notification of coming changes to the PTCID but there is no need to specify what the changes are. Then R3 requires notification again to the same entities with an actual copy of the changes. R2 as written is an administrative requirement that provides no reliability benefit.Resource Planners should receive copies of the Transfer Capabilities in R5 as well. They need to know their import capabilities in order to determine if they have access to sufficient generation to cover their load.
Response: The SDT believes the Planning Coordinator should be afforded the flexibility to include more or fewer paths in its PTCMD if it believes it appropriate. **The SDT agrees with your suggestion to combine R2 and R3 and they have been combined in this second draft of the proposed standard.** **Resource Planners with a reliability related need, will be able to request PTC data.**		
Xcel Energy	Yes	It is not clear why the document focuses on Transmission Operators and not the traditional way in calculating transfer capabilities such as from BA to BA, region to region, sub-region to sub-region. The document should

Organization	Yes or No	Question 13 Comment
		simply require the PC to identify what necessary interfaces it will calculate transfer capabilities on.
Response: The SDT believes the Planning Coordinator should be afforded the flexibility to include more or fewer paths in its PTCMD if it believes it appropriate		
Duke Energy	Yes	o Delete Requirements R2.2 and R2.3 because TSPs and TOPs really have no need of the PTCID. o Requirement R4 specifies a frequency that is overly prescriptive/granular and unnecessary for assessments in the planning timeframe. Suggested rewording: "Consistent with its PTCID, each Planning Coordinator shall assess PTCs in the near-term planning horizon and the long-term planning horizon at least once every two years." o Change the time in Requirement R5 from 10 days to 45 days, since this is a planning timeframe requirement. o Reword Requirement R5.2 to indicate that any other registered entities (not just those specified in R2) that have a reliability-related need can make a written request and receive the PTCs. o Add a new Requirement R5.3 as follows: "Each Planning Coordinator adjacent to the Planning Coordinator's planning coordinator area." o Under Data Retention, there is a typo in the second bullet: ATCID should be PTCID.
Response: The SDT agrees TSPs and TOPs do not have a reliability related need and has dropped them from Requirement R2. **The SDT has removed the requirement to study all four seasons and modified the requirement to now read "Each Planning Coordinator shall verify, and if necessary recalculate, PTCs consistent with its PTCMD for years two through five at least once each calendar year, with no more than 15 months between verifications." The SDT feels that studying years 2 through 5 is appropriate."** **Requirement R5 has been modified to allow 30 calendar days for making PTCs available.** **The SDT agrees and has modified Requirement R5, Part5.2 (now Requirement R5) to reflect your suggested modification to allow those with a reliability-related need access to PTCs as well as adjacent Planning Coordinators.** **Under Data Retention, the typo in the first bullet has been corrected to refer to PTCMD.**		
Southern Company Transmission	Yes	Southern disagrees with requirement R1.1.2 in that a Planning Coordinator should have to provide a detailed explanation as to why the methods used to calculate PTCs are or are not different from those methods selected by the Transmission Operator as described in the Transmission Service Providers ATCID. The methods selected by the Transmission Operator in the ATCID do not provide the framework to calculate Transfer Capabilities beyond 13 months. Additionally, Southern disagrees with requirement R.1.1.3 to provide a justification as to why a method identified in a Planning Coordinator's PTCID is inconsistent with the Transmission Service Provider's ATCID.

Organization	Yes or No	Question 13 Comment
		The existing, FERC approved MOD-001-1 allows for a path of which ATC is calculated to utilize different methodologies for different timeframes. For example, a Transmission Service Provider could select MOD-28-1 (Area Interchange) to utilize when calculating Transfer Capabilities for use in Hourly ATC calculations and select MOD-29-1 (Rated System Path) to utilize when calculating Transfer Capabilities for use in Monthly ATC calculations without requiring any justification for why the Transmission Service Provider chose to select different methods for the different timeframes. As such, Southern does not agree with any requirement to justify why a Planning Coordinator chose a different method for calculating Transfer Capabilities beyond 13 months. Southern disagrees with requirement R4 in that the calculation of seasonal transfer capabilities should be calculated for years two through five. Southern does not believe that there is a reliability need for Planning Coordinators to calculate seasonal PTCs. Each Planning Coordinator determines the most critical system condition for their respective area and performs reliability evaluations on these critical system conditions when creating their reliability expansion plan. Therefore, each Planning Coordinator should not be required to calculate seasonal PTCs for a timeframes that haven't been defined as a critical system condition for their area. Southern recommends that yearly Transfer Capabilities should be the only Transfer Capabilities calculated beyond 13 months through five years and that these Transfer Capabilities be calculated no more than annually.
Response: The SDT has removed Requirement R1, Parts 1.1.2 and 1.1.3. **The SDT has removed the requirement to study all four seasons and modified the requirement to now read "Each Planning Coordinator shall verify, and if necessary recalculate, PTCs consistent with its PTCMD for years two through five at least once each calendar year, with no more than 15 months between verifications." The SDT feels that studying years 2 through 5 is appropriate.**		
SERC Planning Standards Subcommittee	Yes	We recommend that part 5.2 under R5 be restated as: "Any other entities that demonstrate that they have a reliability-related need for such PTCs and make a written request for such PTCs." We recommend that part 1.1 under R1 be restated as: "A list of all Transmission Operators for which the Planning Coordinator determines Planning Transfer Capabilities. Include the following for each of these Transmission Operators." In the first bullet under D.1.4, change "ATCID" to "PTCID." We agree with the MISO comments that: 1) It is not clear why the document focuses on Transmission Operators and not the traditional way in calculating transfer capabilities such as from BA to BA, region to region, sub-region to sub-region. The document should simply require the PC to identify what necessary interfaces it will calculate transfer capabilities on. 2) R2 and R3 should be combined into a single requirement. R2 in essence requires pre-notification of coming changes to the PTCID but there is no need to specify what the changes are. Then R3 requires

Organization	Yes or No	Question 13 Comment
		notification again to the same entities with an actual copy of the changes. R2 as written is an administrative requirement that provides no reliability benefit. The comments expressed herein represent a consensus of the views of the above named members of the SERC Planning Standards Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board or its officers.

Response: The SDT has modified Requirement R5 to allow those entities with a reliability related need to have access to PTCs.

The SDT has revised Requirement R1, Part 1.1 and the SDT believes that this revision accomplishes your suggested change.

Under Data Retention, the typo in the first bullet has been corrected to refer to PTCMD.

The SDT believes the Planning Coordinator should be afforded the flexibility to include more or fewer paths in its PTCMD if it believes it appropriate.

The SDT agrees with your suggestion to combine R2 and R3 and they have been combined in this second draft of the proposed standard.

A. Introduction

1. **Title:** **Establish and Communicate Transfer Capabilities**

2. **Number:** FAC-013-1

3. **Purpose:** To ensure that Transfer Capabilities used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

4. **Applicability**

   4.1. Reliability Coordinator required by its Regional Reliability Organization to establish inter-regional and intra-regional Transfer Capabilities

   4.2. Planning Authority required by its Regional Reliability Organization to establish inter-regional and intra-regional Transfer Capabilities

5. **Effective Date:** October 7, 2006

B. Requirements

R1. The Reliability Coordinator and Planning Authority shall each establish a set of inter-regional and intra-regional Transfer Capabilities that is consistent with its current Transfer Capability Methodology.

R2. The Reliability Coordinator and Planning Authority shall each provide its inter-regional and intra-regional Transfer Capabilities to those entities that have a reliability-related need for such Transfer Capabilities and make a written request that includes a schedule for delivery of such Transfer Capabilities as follows:

R2.1. The Reliability Coordinator shall provide its Transfer Capabilities to its associated Regional Reliability Organization(s), to its adjacent Reliability Coordinators, and to the Transmission Operators, Transmission Service Providers and Planning Authorities that work in its Reliability Coordinator Area.

R2.2. The Planning Authority shall provide its Transfer Capabilities to its associated Reliability Coordinator(s) and Regional Reliability Organization(s), and to the Transmission Planners and Transmission Service Provider(s) that work in its Planning Authority Area.

C. Measures

M1. The Reliability Coordinator and Planning Authority shall each be able to demonstrate that it developed its Transfer Capabilities consistent with its Transfer Capability Methodology.

M2. The Reliability Coordinator and Planning Authority shall each have evidence that it provided its Transfer Capabilities in accordance with schedules supplied by the requestors of such Transfer Capabilities.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility
   Regional Reliability Organization

   1.2. Compliance Monitoring Period and Reset Timeframe

   The Reliability Coordinator and Planning Authority shall each verify compliance through self-certification submitted to the Compliance Monitor annually. The Compliance

Monitor may conduct a targeted audit once in each calendar year (January–December) and an investigation upon a complaint to assess compliance.

The Performance-Reset Period shall be twelve months from the last finding of non-compliance.

1.3. Data Retention

The Planning Authority and Reliability Coordinator shall each keep documentation for 12 months. In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant.

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Planning Authority and Reliability Coordinator shall each make the following available for inspection during a targeted audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 Transfer Capability Methodology.

1.4.2 Inter-regional and Intra-regional Transfer Capabilities.

1.4.3 Evidence that Transfer Capabilities were distributed.

1.4.4 Distribution schedules provided by entities that requested Transfer Capabilities.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: Not all requested Transfer Capabilities were provided in accordance with their respective schedules.

2.3. Level 3: Transfer Capabilities were not developed consistent with the Transfer Capability Methodology.

2.4. Level 4: No requested Transfer Capabilities were provided in accordance with their respective schedules.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
1	08/01/05	1. Changed incorrect use of certain hyphens (-) to “en dash (–).” 2. Lower cased the word “draft” and “drafting team” where appropriate. 3. Changed Anticipated Action #5, page 1, from “30-day” to “Thirty-day.” 4. Added or removed “periods.”	01/20/05

A. Introduction

1. **Title:** **Transfer Capability Methodology**

2. **Number:** FAC-012-1

3. **Purpose:** To ensure that Transfer Capabilities used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

4. **Applicability**

   4.1. Reliability Coordinator required by its Regional Reliability Organization to establish inter-regional and intra-regional Transfer Capabilities

   4.2. Planning Authority required by its Regional Reliability Organization to establish inter-regional and intra-regional Transfer Capabilities

5. **Effective Date:** August 7, 2006

B. Requirements

R1. The Reliability Coordinator and Planning Authority shall each document its current methodology used for developing its inter-regional and intra-regional Transfer Capabilities (Transfer Capability Methodology). The Transfer Capability Methodology shall include all of the following:

R1.1. A statement that Transfer Capabilities shall respect all applicable System Operating Limits (SOLs).

R1.2. A definition stating whether the methodology is applicable to the planning horizon or the operating horizon.

R1.3. A description of how each of the following is addressed, including any reliability margins applied to reflect uncertainty with projected BES conditions:

R1.3.1. Transmission system topology

R1.3.2. System demand

R1.3.3. Generation dispatch

R1.3.4. Current and projected transmission uses

R2. The Reliability Coordinator shall issue its Transfer Capability Methodology, and any changes to that methodology, prior to the effectiveness of such changes, to all of the following:

R2.1. Each Adjacent Reliability Coordinator and each Reliability Coordinator that indicated a reliability-related need for the methodology.

R2.2. Each Planning Authority and Transmission Planner that models any portion of the Reliability Coordinator's Reliability Coordinator Area.

R2.3. Each Transmission Operator that operates in the Reliability Coordinator Area.

R3. The Planning Authority shall issue its Transfer Capability Methodology, and any changes to that methodology, prior to the effectiveness of such changes, to all of the following:

R3.1. Each Transmission Planner that works in the Planning Authority's Planning Authority Area.

R3.2. Each Adjacent Planning Authority and each Planning Authority that indicated a reliability-related need for the methodology.

R3.3. Each Reliability Coordinator and Transmission Operator that operates any portion of the Planning Authority's Planning Authority Area.

R4. If a recipient of the Transfer Capability Methodology provides documented technical comments on the methodology, the Reliability Coordinator or Planning Authority shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the Transfer Capability Methodology and, if no change will be made to that Transfer Capability Methodology, the reason why.

C. Measures

M1. The Planning Authority and Reliability Coordinator's methodology for determining Transfer Capabilities shall each include all of the items identified in FAC-012 Requirement 1.1 through Requirement 1.3.4.

M2. The Reliability Coordinator shall have evidence it issued its Transfer Capability Methodology in accordance with FAC-012 Requirement 2 through Requirement R2.3.

M3. The Planning Authority shall have evidence it issued its Transfer Capability Methodology in accordance with FAC-012 Requirement 3 through Requirement 3.3.

M4. If the recipient of the Transfer Capability Methodology provides documented comments on its technical review of that Transfer Capability Methodology, the Reliability Coordinator or Planning Authority that distributed that Transfer Capability Methodology shall have evidence that it provided a written response to that commenter in accordance with FAC-012 Requirement 4.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Timeframe

Each Planning Authority and Reliability Coordinator shall self-certify its compliance to the Compliance Monitor at least once every three years. New Planning Authorities and Reliability Coordinators shall each demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last finding of non-compliance.

1.3. Data Retention

The Planning Authority and Reliability Coordinator shall each keep all superseded portions to its Transfer Capability Methodology for 12 months beyond the date of the change in that methodology and shall keep all documented comments on the Transfer Capability Methodology and associated responses for three years. In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant.

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Planning Authority and Reliability Coordinator shall each make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 Transfer Capability Methodology.

1.4.2 Superseded portions of its Transfer Capability Methodology that have been made within the past 12 months.

1.4.3 Documented comments provided by a recipient of the Transfer Capability Methodology on its technical review of the Transfer Capability Methodology, and the associated responses.

2. Levels of Non-Compliance

2.1. Level 1: There shall be a level one non-compliance if either of the following conditions exists:

2.1.1 The Transfer Capability Methodology is missing any one of the required statements or descriptions identified in FAC-012 R1.1 through R1.3.4.

2.1.2 No evidence of responses to a recipient's comments on the Transfer Capability Methodology.

2.2. Level 2: The Transfer Capability Methodology is missing a combination of two of the required statements or descriptions identified in FAC-012 R1.1 through R1.3.4, or a combination thereof.

2.3. Level 3: The Transfer Capability Methodology is missing a combination of three or more of the required statements or descriptions identified in FAC-012 R1.1 through R1.3.4.

2.4. Level 4: The Transfer Capability Methodology was not issued to all of the required entities.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
1	08/01/05	1. Lower cased the word "draft" and "drafting team" where appropriate. 2. Changed incorrect use of certain hyphens (-) to "en dash" (–) and "em dash (—)." 3. Changed "Timeframe" to "Time Frame" in item D, 1.2.	01/20/06

The following tables provide the FAC-013 Order 729 drafting team's justification for the VRFs and VSLs proposed in FAC-013-2 – Planning Transfer Capability. The NERC and FERC guidelines for VRFs and VSLs are provided at the end of this document.

FAC-013-2 VSL and VRF Justifications		
R1	Proposed VRF	Lower
	NERC VRF Discussion	A Planning Coordinator that violated this requirement would not be placing the BES in any risk situation. This requirement is completely administrative in nature.
	FERC VRF G1 Discussion	The requirement is related to the planning time frame. Violation of documenting the methodology used to calculate PTC's would not put the BES in any risk situation.
	FERC VRF G2 Discussion	This requirement only utilizes sub-requirements to identify the items to be included within the methodology document. The VRF for this requirement is consistent with others in the standard with regard to relative risk.
	FERC VRF G3 Discussion	The requirement is consistent with other data input and modeling standards. As this requirement only addresses the documentation of the methodology used to calculate PTCs it is appropriate that this requirement have a VRF of Lower.
	FERC VRF G4 Discussion	The requirement is strictly administrative in nature and is in the planning timeframe. If violated, it is not anticipated that under emergency, abnormal or restorative conditions violation of this requirement would be expected to affect the electrical state or capability of the BES.
	FERC VRF G5 Discussion	This requirement does not co-mingle reliability objectives.
	Proposed Lower VSL	The Planning Coordinator has a PTCMD but failed to address one or two of the items listed in Requirement R1, Part 1.1.
	Proposed Moderate VSL	The Planning Coordinator has a PTCMD but failed to incorporate 1 of the items listed in Requirement R1, Parts 1.2 through 1.5 OR The Planning Coordinator has a PTCMD but failed to address two or more of the items listed in Requirement R1, Part 1.1.
	Proposed High VSL	The Planning Coordinator has a PTCMD but failed to incorporate 2 of the items listed in Requirement R1, Parts 1.2 through 1.5.
	Proposed Severe VSL	The Planning Coordinator does not have a PTCMD. OR The Planning Coordinator has a PTCMD but failed to incorporate 3 or more of the items listed in Requirement R1, Parts 1.2 through 1.5.
	FERC VSL G1 Discussion	No longer applicable given significant changes in standard structure.
	FERC VSL G2 Discussion	The VSL is not written as a pass/fail VSL and does not include ambiguous terms.
	FERC VSL G3 Discussion	The VSL aligns with the language of the requirement, and does not add to nor take away from it.
	FERC VSL G4 Discussion	The VSL is based on a single violation of the requirement.

FAC-013-2 VSL and VRF Justifications		
R2	Proposed VRF	Lower
	NERC VRF Discussion	A Planning Coordinator that violated this requirement would not be putting the BES in any immediate risk situation. This standard is addressing the timeframe of beyond 13 months.
	FERC VRF G1 Discussion	A Planning Coordinator that violated this requirement would not be putting the BES in any immediate risk situation. This standard is addressing the timeframe of beyond 13 months.
	FERC VRF G2 Discussion	This requirement only utilizes sub-requirements to identify the individuals who should receive the methodology documentation. The VRF for this requirement is consistent with others in the standard with regard to relative risk.
	FERC VRF G3 Discussion	The VRF for this requirement is consistent with other data input and modeling standards. As this requirement only addresses who should receive the documented methodology used to calculate PTC's it is appropriate that this requirement have a VRF of Lower.
	FERC VRF G4 Discussion	The requirement is strictly administrative in nature and is in the planning timeframe, beyond 13 months. If violated, it is not anticipated that under emergency, abnormal or restorative conditions violation of this requirement would be expected to affect the electrical state or capability of the BES.
	FERC VRF G5 Discussion	This requirement does not co-mingle reliability objectives.
	Proposed Lower VSL	The Planning Coordinator notified one or more of the parties specified in R2 of a new or revised PTCMD after its implementation, but not more than 30 calendar days after its implementation.
	Proposed Moderate VSL	The Planning Coordinator notified one or more of the parties specified in R2 of a new or revised PTCMD more than 30 calendar days after its implementation, but not more than 40 calendar days after its implementation.
	Proposed High VSL	The Planning Coordinator notified one or more of the parties specified in R2 of a new or revised PTCMD more than 40 calendar days, but not more than 50 calendar days after its implementation.
	Proposed Severe VSL	The Planning Coordinator failed to notify one or more of the parties specified in R2 of a new or revised PTCMD more than 50 calendar days after its implementation.
	FERC VSL G1 Discussion	No longer applicable given significant changes in standard structure.
	FERC VSL G2 Discussion	The VSL is not written as a pass/fail and does not contain any ambiguous terms...
	FERC VSL G3 Discussion	The VSL aligns with the language of the requirement, and does not add to nor take away from it.
	FERC VSL G4 Discussion	The VSL is based on a single violation of the requirement.

FAC-013-2 VSL and VRF Justifications		
R3	Proposed VRF	Lower
	NERC VRF Discussion	A Planning Coordinator that failed to respond to comments received on their methodology document would not be putting the BES in any immediate risk situation. This standard is addressing the timeframe of beyond 13 months.
	FERC VRF G1 Discussion	A Planning Coordinator that failed to respond to comments received on their methodology document would not be putting the BES in any immediate risk situation. This standard is addressing the timeframe of beyond 13 months.
	FERC VRF G2 Discussion	This requirement does not utilize sub-requirements. The VRF for this requirement is consistent with others in the standard with regard to relative risk.
	FERC VRF G3 Discussion	The VRF for this requirement is consistent with other data input and modeling standards. As this requirement only addresses who should receive the documented methodology used to calculate PTC's it is appropriate that this requirement have a VRF of Lower.
	FERC VRF G4 Discussion	The requirement is strictly administrative in nature and is in the planning timeframe, beyond 13 months. This requirement only addresses responding to comments received on their methodology document. If violated, it is not anticipated that under emergency, abnormal or restorative conditions violation of this requirement would be expected to affect the electrical state or capability of the BES.
	FERC VRF G5 Discussion	This requirement does not co-mingle reliability objectives.
	Proposed Lower VSL	The Planning Coordinator provided a documented response to a documented technical comment as required in Requirement R3 after 45 calendar days, but not more than 60 calendar days after receipt of the comment.
	Proposed Moderate VSL	The Planning Coordinator provided a documented response to a documented technical comment as required in R3 after 60 calendar days, but not more than 70 calendar days after receipt of the comment.
	Proposed High VSL	The Planning Coordinator provided a documented response to a documented technical comment as required in R3 after 80 calendar days after receipt of the comment.
	Proposed Severe VSL	The Planning Coordinator failed to provide a documented response to a documented technical comment as required in R3.
	FERC VSL G1 Discussion	No longer applicable given significant changes in standard structure.
	FERC VSL G2 Discussion	The VSL is not written as a pass/fail VSL, and it is written in clear and unambiguous language.
	FERC VSL G3 Discussion	The VSL aligns with the language of the requirement, and does not add to nor take away from it.
	FERC VSL G4 Discussion	The VSL is based on a single violation of the requirement.

FAC-013-2 VSL and VRF Justifications		
R4	Proposed VRF	Lower
	NERC VRF Discussion	A Planning Coordinator that failed to recalculate its PTC's would not be putting the BES in any immediate risk situation. This standard is addressing the timeframe of beyond 13 months and would not have any immediate impact on the BES.
	FERC VRF G1 Discussion	A Planning Coordinator that failed to recalculate its PTC's would not be putting the BES in any immediate risk situation. This standard is addressing the timeframe of beyond 13 months and would not have any immediate impact on the BES.
	FERC VRF G2 Discussion	This requirement does not utilize sub-requirements. The VRF for this requirement is consistent with others in the standard with regard to relative risk.
	FERC VRF G3 Discussion	The VRF for this requirement is consistent with other data input and modeling standards. Since this requirement is addressing calculation of PTC's in the planning horizon, beyond 13 months it is appropriate that this requirement have a VRF of Lower.
	FERC VRF G4 Discussion	The requirement is strictly administrative in nature and is in the planning timeframe, beyond 13 months. This requirement only addresses calculation of PTC's within the planning horizon and if violated, it is not anticipated that under emergency, abnormal or restorative conditions violation of this requirement would be expected to affect the electrical state or capability of the BES.
	FERC VRF G5 Discussion	This requirement does not co-mingle reliability objectives.
	Proposed Lower VSL	The Planning Coordinator failed to verify and recalculate, if necessary, 5% or less of its PTCs, as specified in the PTCMD.
	Proposed Moderate VSL	The Planning Coordinator failed to verify and recalculate, if necessary, more than 5% up to and including 10% of its PTCs as specified in the PTCMD.
	Proposed High VSL	The Planning Coordinator failed to verify and recalculate, if necessary, more than 10% up to and including 15% of its PTCs, as specified in the PTCMD.
	Proposed Severe VSL	The Planning Coordinator failed to verify and recalculate, if necessary, more than 15% of its PTCs, as specified in the PTCMD.
	FERC VSL G1 Discussion	No longer applicable given significant changes in standard structure.
	FERC VSL G2 Discussion	The VSL is written as a pass/fail VSL, and it has been set at the "Severe" level, meeting guideline 2A. The VSL is written in clear and unambiguous language, meeting Guideline 2B.
	FERC VSL G3 Discussion	The VSL aligns with the language of the requirement, and does not add to nor take away from it.
	FERC VSL G4 Discussion	The VSL is based on a single violation of the requirement.

FAC-013-2 VSL and VRF Justifications		
R5	Proposed VRF	Lower
	NERC VRF Discussion	A Planning Coordinator that failed to share its calculated PTCs would not be putting the BES in any immediate risk situation. This standard is addressing the timeframe of beyond 13 months.
	FERC VRF G1 Discussion	A Planning Coordinator that failed to share its calculated PTC's would not be putting the BES in any immediate risk situation. This standard is addressing the timeframe of beyond 13 months.
	FERC VRF G2 Discussion	This requirement does not utilize sub-requirements. The VRF for this requirement is consistent with others in the standard with regard to relative risk.
	FERC VRF G3 Discussion	The VRF for this requirement is consistent with other data input and modeling standards. As this requirement only addresses when and who should receive the calculated PTCs it is appropriate that this requirement have a VRF of Lower.
	FERC VRF G4 Discussion	The requirement is strictly administrative in nature and is in the planning timeframe, beyond 13 months. This requirement only addresses when and who should received its PTCs. If violated, it is not anticipated that under emergency, abnormal or restorative conditions violation of this requirement would be expected to affect the electrical state or capability of the BES.
	FERC VRF G5 Discussion	This requirement does not co-mingle reliability objectives.
	Proposed Lower VSL	The Planning Coordinator notified one or more of the parties specified in Requirement R5 of its PTCs more than 30 calendar days after their verification and recalculation, but not more than 60 calendar days after their verification and recalculation.
	Proposed Moderate VSL	The Planning Coordinator notified one or more of the parties specified in Requirement R5 of its PTCs more than 60 calendar days after their verification and recalculation, but not more than 70 calendar days after their verification and recalculation.
	Proposed High VSL	The Planning Coordinator notified one or more of the parties specified in Requirement R5 of its PTCs more than 70 calendar days after their verification and recalculation.
	Proposed Severe VSL	The Planning Coordinator failed to notify one or more of the parties specified in Requirement R5 of its PTCs after their verification and recalculation.
	FERC VSL G1 Discussion	No longer applicable given significant changes in standard structure.
	FERC VSL G2 Discussion	The VSL is not written as a pass/fail and is written in clear and unambiguous language.
	FERC VSL G3 Discussion	The VSL aligns with the language of the requirement, and does not add to nor take away from it.
	FERC VSL G4 Discussion	The VSL is based on a single violation of the requirement.

Violation Risk Factors

NERC's VRF Guidelines:

Each requirement must have an associated violation risk factor (High, Medium or Lower). The risk factor assesses the impact to reliability of violating a specific requirement. The following criteria have been filed with FERC as part of the ERO's Sanctions Guidelines and must be used to determine a violation risk factor for each requirement:

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

FERC's VRF Guidelines:

In addition, in its May 18, 2007 Order on Violation Risk Factors, FERC identified five "guidelines" it uses to determine whether to approve the Violation Risk Factors submitted for approval. Those factors are:

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. From footnote 15 of the May 18, 2007 Order, FERC's list of critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System includes:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) – Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) –Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

Violation Severity Levels

NERC's VSL Guidelines:

Violation Severity Levels (VSLs) define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

Violation severity levels should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC's VSL Guidelines:

In its June 19, 2008 *Order on Violation Severity Levels*, FERC indicated it would use the following four guidelines for determining whether to approve VSLs:

Guideline (1): Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance (Compare the VSLs to any prior Levels of Non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when Levels of Non-compliance were used.)

Guideline (2): Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties (A violation of a "binary" type requirement must be a "Severe" VSL. Avoid using ambiguous terms such as "minor" and "significant" to describe noncompliant performance.)

Guideline(3): Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement (VSLs should not expand on what is required in the requirement.)

Guideline (4): Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations (. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.)

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Mapping Table Showing Translation of FAC-012-1 – Transfer Capability Methodology and FAC-013-1 – Establish and Communicate Transfer Capabilities into FAC-013-2 – Planning Transfer Capability

Standard: FAC-012-1- Transfer Capability Methodology		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language in FAC-013-2/Comments**
R1. The Reliability Coordinator and Planning Authority shall each document its current methodology used for developing its inter-regional and intra-regional Transfer Capabilities (Transfer Capability Methodology). The Transfer Capability Methodology shall include all of the following: R1.1. A statement that Transfer Capabilities shall respect all applicable System Operating Limits (SOLs). R1.2. A definition stating whether the methodology is applicable to the planning horizon or the operating horizon. R1.3. A description of how each of the following is addressed, including any reliability margins applied to reflect uncertainty with projected BES conditions: R1.3.1. Transmission system topology R1.3.2. System demand R1.3.3. Generation dispatch R1.3.4. Current and projected transmission uses	This Requirement has been moved into FAC-013-2 Requirement R1	The Reliability Coordinator has been removed as an applicable entity in FAC-013-2. R1. Each Planning Coordinator shall prepare and keep current a Planning Transfer Capability Methodology Document (PTCMD) that includes, at a minimum, the following information: 1.1. A description of the assumptions and criteria used in the calculation of Planning Transfer Capabilities (PTCs) to include at a minimum how each of the following are addressed, or an explanation for any of the following not used in the calculation of PTC. • Generation dispatch, including expected outages, additions and retirements • Transmission system topology, including expected transmission outages, additions, and retirements • System demand • Current and projected transmission uses • Parallel path impacts (loop flows) • Contingencies • Reliability margins applied to reflect uncertainty with BES conditions. 1.2. A list of all PTCs to be calculated. 1.3. A statement that PTCs shall respect all applicable System Operating Limits (SOLs). 1.4. A statement that the assumptions and criteria used to

Standard: FAC-012-1- Transfer Capability Methodology		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language in FAC-013-2/Comments**
		calculate PTCs are as, or more, limiting than the assumptions and criteria used in the operating horizon. 1.5. A description of how generation/load is adjusted to determine the PTCs identified in Requirement R1, Part 1.2.
R2. The Reliability Coordinator shall issue its Transfer Capability Methodology, and any changes to that methodology, prior to the effectiveness of such changes, to all of the following: R2.1. Each Adjacent Reliability Coordinator and each Reliability Coordinator that indicated a reliability-related need for the methodology. R2.2. Each Planning Authority and Transmission Planner that models any portion of the Reliability Coordinator's Reliability Coordinator Area. R2.3. Each Transmission Operator that operates in the Reliability Coordinator Area.	This Requirement has been removed from FAC-013-2.	FAC-013-2 only applies to the Planning Coordinator.
R3. The Planning Authority shall issue its Transfer Capability Methodology, and any changes to that methodology, prior to the effectiveness of such changes, to all of the following: R3.1. Each Transmission Planner that works in the Planning Authority's Planning	This Requirement has been moved into FAC-013-2 Requirement R2.	R2. Each Planning Coordinator shall issue its PTCMD, and any revisions to the PTCMD, to the following entities prior to the effectiveness of such revisions: 2.1. Each Planning Coordinator adjacent to the Planning Coordinator's planning coordinator area. 2.2. Each Transmission Planner within the Planning Coordinator's planning coordinator area.

Standard: FAC-012-1- Transfer Capability Methodology		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language in FAC-013-2/Comments**
Authority Area. R3.2. Each Adjacent Planning Authority and each Planning Authority that indicated a reliability-related need for the methodology. R3.3. Each Reliability Coordinator and Transmission Operator that operates any portion of the Planning Authority's Planning Authority Area.		2.3. Any other functional entity that has a reliability-related need for such PTCs and makes a written request for such PTCs. FAC-012-1 Requirement R3.3 has been modified to include any functional entity that has a reliability-related need (FAC-013-2 Requirement R2 Part 2.3).
R4. If a recipient of the Transfer Capability Methodology provides documented technical comments on the methodology, the Reliability Coordinator or Planning Authority shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the Transfer Capability Methodology and, if no change will be made to that Transfer Capability Methodology, the reason why.	This Requirement has been moved into FAC-013-2 Requirement R3.	R3. If a recipient of the PTCMD provides documented technical comments on the methodology, the Planning Coordinator shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the PTCMD and, if no change will be made to that PTCMD, the reason why.

Standard: FAC-013-1 - Establish and Communicate Transfer Capabilities		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language in FAC-013-2/Comments**
R1. The Reliability Coordinator and Planning Authority shall each establish a set of inter-regional and intra-regional Transfer Capabilities that is consistent with its current Transfer Capability Methodology.	This Requirement has been moved into FAC-013-2 Requirement R4.	R4. Each Planning Coordinator shall verify, and if assumptions or criteria as described in Requirement 1 Part 1.1 have changed recalculate, PTCs consistent with its PTCMD for years two through five at least once each calendar year with no more than 15 months between verifications.

Standard: FAC-013-1 - Establish and Communicate Transfer Capabilities		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language in FAC-013-2/Comments**
R2. The Reliability Coordinator and Planning Authority shall each provide its inter-regional and intra-regional Transfer Capabilities to those entities that have a reliability-related need for such Transfer Capabilities and make a written request that includes a schedule for delivery of such Transfer Capabilities as follows: R2.1. The Reliability Coordinator shall provide its Transfer Capabilities to its associated Regional Reliability Organization(s), to its adjacent Reliability Coordinators, and to the Transmission Operators, Transmission Service Providers and Planning Authorities that work in its Reliability Coordinator Area. R2.2. The Planning Authority shall provide its Transfer Capabilities to its associated Reliability Coordinator(s) and Regional Reliability Organization(s), and to the Transmission Planners and Transmission Service Provider(s) that work in its Planning Authority Area.	This Requirement has been moved into FAC-013-2 Requirement R5.	The Reliability Coordinator is not an applicable entity in FAC-013-2 therefore FAC-013-1 Requirement R2.1 has been removed. R5. The Planning Coordinator shall make its PTCs available no later than thirty calendar days (following the verification or recalculation of those PTCs) to those entities identified in Requirement R2. FAC-013-1 Requirement R2.2 has been modified to include adjacent Planning Coordinator's, Transmission Planner's within the Planning Coordinator area and any functional entity that has a reliability-related need (FAC-013-2 Requirement R2, Part 2.1 through Part 2.3). R2. Each Planning Coordinator shall issue its PTCMD, and any revisions to the PTCMD, to the following entities prior to the effectiveness of such revisions: 2.1. Each Planning Coordinator adjacent to the Planning Coordinator's planning coordinator area. 2.2. Each Transmission Planner within the Planning Coordinator's planning coordinator area. 2.3. Any other functional entity that has a reliability-related need for such PTCs and makes a written request for such PTCs.

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FAC-013-2 — Planning Transfer Capability White Paper

Through FERC Orders 693 (paragraphs 782 and 794) and 729 (paragraphs 278, 279, 289, 290 and 291), FERC directed NERC to establish a standard requiring Planning Coordinators to calculate transfer capability in the planning horizon and communicate the results. In the FERC Order approving the MOD standards related to Available Transfer Capability (ATC)/Available Flowgate Capability (AFC) calculations (MOD-001-1 — Available Transmission System Capability, MOD-028-1— Area Interchange Methodology , MOD-029-1 — Rated System Path Methodology, and MOD-030-2 — Flowgate Methodology), FERC did not approve NERC's request to withdraw FAC-012-1 — Transfer Capability Methodology, nor did they approve the retirement of FAC-013-1 — Establish and Communicate Transfer Capabilities. With respect to these two Reliability Standards, the Commission disagreed with NERC that they are wholly superseded by the MOD Reliability Standards.

- The Commission noted that, under FAC-012-1, Reliability Coordinators and Planning Authorities would be required to document the methodology used to establish inter-regional and intra-regional transfer capabilities and to state whether the methodology is applicable to the planning horizon or the operating horizon.

- The Commission also noted that, under FAC-013-1, Reliability Coordinators and Planning Authorities are required to establish a set of inter-regional and intra-regional transfer capabilities that are consistent with the methodology documented under FAC-012-1, which could require the calculation of transfer capabilities for both the planning horizon and the operating horizon.

- The Commission posited that these FAC Reliability Standards were necessary because the proposed MOD Reliability Standards provide only for the calculation of available transfer capability and its components, including total transfer capability, in the operating horizon. Thus, the Commission stated, the proposed MOD Reliability Standards do not govern the calculation of transfer capabilities in the planning horizon, i.e., beyond 13 months in the future.

- The Commission also noted, that the calculation of transfer capabilities in the planning horizon (years one through five) may not be so accurate to support long-term scheduling of the transmission system but that such forecasts will be useful for long-term planning, in general, by measuring sufficient long-term capacity needed to ensure the reliable operation of the bulk power system.

- The Commission stated that the responsibility for calculation of transfer capabilities in the planning horizon would be appropriately assigned to the Planning Coordinator and not the Reliability Coordinator.

Consistent with the above philosophy and to address FERC's concerns, FAC-013-2 is only applicable to the Planning Coordinator. Further, FAC-013-2 requires that a Planning Transfer Capability Methodology Document (PTCMD) be developed for the calculation of Planning

Transfer Capabilities (PTC) beyond 13 months in the future to provide additional information for the Planning Coordinator to use in planning for BES reliability. This information is not intended in any way to be associated with the granting or denial of transmission service.

The PTC definition is introduced to clarify that the calculations performed in accordance with FAC-013-2 (beyond 13 months) are not directly related to calculations of TTC and ATC. The standalone definition of PTC will ensure that communications involving calculation of PTCs for reliability purposes are clear and cannot be confused with issues related to other forms of transfer capability having different purposes.

PTC calculations are not intended to supersede nor replace calculations done to meet FAC-010 and FAC-014 requirements related to calculation of System Operating Limits (SOL). SOL calculations are done based on the specific requirements of FAC-010 and FAC-014, whereas the Planning Coordinator determines the methodology for PTC calculation based on its system needs and within the framework provided by FAC-013-2.

The criteria used in planning the system, and the appropriate analyses to assess system plans are detailed in the TPL series of standards. The TPL planning standards do not specify the need to document transfer capability calculation methods that may be used in the planning horizon. To cover that aspect of planning for BES reliability, the FAC-013-2 standard specifies that Planning Coordinators must perform PTC calculations as part of the planning process, that the method must be documented and shared with other entities as specified in the standard. Additionally, the standard is not intended to supersede nor replace transfer tests performed as part of specific planning processes internal to a Balancing Authority, such as generation or load deliverability tests which are not specifically addressed by this standard.

Requirement R1, Part 1.2 requires a description of several elements that must be included in the PTCMD. This description is intended to provide context for the PTC values derived from the PTCMD. Knowledge of these details of the methodology will allow those receiving PTC data to better understand the implications of the PTC values and their potential impact on BES reliability. Some guidance is provided for each of the required elements:

> Generation dispatch should include a discussion of how generation outages are included in PTC calculations; whether known outages are included or other methods (e.g. Monte Carlo) are used to represent outages of generation, and if any generation related operating guides are utilized. Entities should identify if generation retirements are modeled and if new/proposed generation is included in the models.
>
> Transmission system topology should include a discussion of how transmission outages are included in PTC calculations; whether known outages are included or other methods are used to represent transmission outages. Additionally, entities should identify whether transmission facility retirements are modeled and if new/proposed transmission facilities are included in the models.

System demand should include a description of the models used (e.g. Multiregional Modeling Working Group, regional, other), seasons, load levels and conditions selected for PTC calculation.

Current and projected transmission uses should include a description for how firm and non-firm transmission service is modeled.

Any parallel path impacts (loop flows) that are added to the base models or affect PTC results should be explained.

A description of the contingencies evaluated should be provided to explain the types of contingencies (e.g. N-1, N-1-1) that drive the PTC values.

Application of any reliability margins affecting PTC results should be explained. For example, any use of Transmission Reliability Margin and Capacity Benefit Margin whether simulated in models or applied in calculations should be explained.

Requirement R1, Part 1.4 is intended to provide consistency in the planning and operating practices for evaluation of the reliability of the BES.

1.4 A statement that the assumptions and criteria used to calculate PTC are as or more limiting than the assumptions and criteria used in the operating horizon.

For example, if an N-1-1 contingency is being evaluated and normal operating and planning practice is to allow for use of Demand Side Management (DSM) to meet performance requirements then the PTC calculation should also allow for use of DSM.

The application of FAC-013-2 will provide PTC values that are an indicator of the robustness of the future transmission system and facilitate communication between adjacent Planning Coordinators. It will result in meeting FERC's concerns regarding transfer capability in the planning horizon and provide important information that Planning Coordinators will be able to apply in their efforts to reliably plan the BES.

Unofficial Comment Form for Project 2010-10 — Modifications to FAC-012 and FAC-013 for Order 729 — Draft FAC-013-2 Standard

Please **DO NOT** use this form. Please use the electronic comment form located at the link below to submit comments on the proposed SAR and modifications proposed FAC-013-2 — Planning Transfer Capability. Comments must be submitted by **November 3, 2010**. If you have questions please contact Darrel Richardson at Darrel.richardson@nerc.net or by telephone at 609-613-1848.

https://www.nerc.net/nercsurvey/Survey.aspx?s=e90004c891d2475ea8f1f74a35d5e2ba

Background Information:
The SAR for Project 2010-10 – Modifications to FAC-012 and FAC-013 for Order 729 proposes modifications to the following standards:

- FAC-012-1 — Transfer Capability Methodology
- FAC-013-1 — Establish and Communicate Transfer Capabilities

In Order 729, FERC ruled that the ATC standards developed in Project 2006-07 did not completely address the topics covered in FAC-012 and -013 and did not fully address the associated directives from Order 693. Accordingly, FERC denied the portions of the implementation plan that would have retired these standards, and instead directed NERC to use the standards development process to make changes to the FAC standards and file those changes with FERC no later than 60 days prior to the effective date of the standards, which is April 1, 2011 (requiring the proposed changes to be filed on or before January 31, 2011).

NERC has an obligation to address FERC's directives. It is the intent to identify all the applicable FERC directives and incorporate them in the draft standard. A second draft of the proposed standard has been developed that attempts to address the applicable FERC directives as well as address concerns raised by the industry during the first posting. Please review the proposed draft standard in its entirety and answer the following questions by using the electronic comment form.

You do not have to answer all questions. Enter all comments in Simple Text Format.

1. The SDT has modified the definition of Planning Transfer Capability (PTC). The definition now reads "The Transfer Capability that is calculated for the planning period beyond 13 months." Do you agree that the revised definition provides additional clarity as to the time period for the calculations?

   ☐ Yes
   ☐ No
   Comments:

2. The SDT has modified the definition of Planning Transfer Capability Implementation Document (PTCID) so that it is now called Planning Transfer Capability Methodology Document (PTCMD). The definition now reads "A document that describes the process

for calculating Planning Transfer Capability (PTC)." Do you agree that the revised definition provides additional clarity as to the purpose of the document?

☐ Yes

☐ No

Comments:

3. The SDT has modified the Requirements to include data and modeling information as well as provide for additional clarity regarding the intent of the Requirement. Do you agree that the revised Requirements accomplish this goal?

   ☐ Yes

   ☐ No

   Comments:

4. The SDT has modified the VRFs to better align with the risk associated with the Requirements. Do you agree that the VRFs are now more consistent with regards to the risk associated with the Requirements?

   ☐ Yes

   ☐ No

   Comments:

5. The SDT has modified the Measures to better align with the Requirements. Do you agree that the Measures are now more consistent with the Requirements?

   ☐ Yes

   ☐ No

   Comments:

6. The SDT has modified the VSLs to better align with the severity of non-compliance associated with the Requirements. Do you agree that the VSLs are now more consistent with regards to the severity of non-compliance associated with the Requirements?

   ☐ Yes

   ☐ No

   Comments:

7. When reviewing the mapping document posted with the proposed FAC-013-2 standard, do you believe that the proposed standard (considering only the requirements assigned to the Planning Coordinator) will be lead to an improvement in reliability when compared to the standards it proposes to replace?

   ☐ Yes

   ☐ No

   Comments:

8. Please provide any other comments (that you have not already provided in response to the questions above) that you have on the proposed standard.

   Comments:

Implementation Plan for Standard FAC-013-2 — Planning Transfer Capability

Prerequisite Approvals

There are no Standard Authorization Requests (SARs) that must be implemented before this standard can be implemented.

FAC-013-2 cannot be implemented before the following standards become effective:

- MOD-001-1 — Available Transmission System Capability
- MOD-028-1— Area Interchange Methodology
- MOD-029-1 — Rated System Path Methodology
- MOD-030-2 — Flowgate Methodology

New or Modified Definitions

The following definitions shall become effective when FAC-013-2 becomes effective:

> **Planning Transfer Capability (PTC):** The Transfer Capability that is calculated for the planning period beyond 13 months.
>
> **Planning Transfer Capability Mehtodology Document (PTCMD):** A document that describes the process for calculating Planning Transfer Capability (PTC).

Modified Standards

FAC-012-1 and FAC-013-1 should be retired when FAC-013-2 becomes effective.

Compliance with Standards

Once the standard becomes effective, the responsible entity identified in the applicability section of the standard must comply with the requirements and calculate an initial set of PTCs within the calendar year immediately following the effective date. This includes

- Planning Coordinator

Proposed Effective Date

In those jurisdictions where regulatory approval is required, the latter of either the first day of the first calendar quarter twelve months after applicable regulatory approval or the first day of the first calendar quarter six months after MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-2 are effective.

In those jurisdictions where no regulatory approval is required, the latter of either the first day of the first calendar quarter twelve months after Board of Trustees adoption or the first day of the first calendar quarter six months after MOD-001-1, MOD-028-1, MOD-029-1 and MOD-030-2 are effective.

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Implementation Plan for Standard FAC-013-2 ~~— (~~Planning Transfer Capability~~)~~

Prerequisite Approvals

There are no ~~other reliability standards or~~ Standard Authorization Requests (SARs)~~, approved or in progress,~~ that must be implemented before this standard can be implemented.

FAC-013-2 cannot be implemented before the following standards become effective:

- MOD-001-1 — Available Transmission System Capability
- MOD-028-1— Area Interchange Methodology
- MOD-029-1 — Rated System Path Methodology
- MOD-030-2 — Flowgate Methodology

New or Modified Definitions

The following definitions shall become effective when FAC-013-2 becomes effective:

Planning Transfer Capability (PTC): The ~~.A forecast of the~~ Transfer Capability that is calculated for the planning period beyond 13 months.~~between areas that is used in the planning horizon when performing planning analyses.~~

Planning Transfer Capability Mehtodology~~Implementation~~ Document (PTCM~~I~~D): A document that describes the process ~~implementation~~ for ~~of a method for~~ calculating Planning Transfer Capability (PTC).~~, and provides information related to a Planning Coordinator's calculation of PTC.~~

Modified Standards

FAC-012-1 and FAC-013-1 should be retired when FAC-013-2 becomes effective.

Compliance with Standards

Once the standard becomes effective, the responsible entity identified in the applicability section of the standard must comply with the requirements and calculate an initial set of PTCs within the calendar year immediately following the effective date. This includes

- Planning Coordinator~~s~~

Proposed Effective Date

In those jurisdictions where regulatory approval is required, the latter of either the first day of the first calendar quarter twelve months after applicable regulatory approval or the first day of the first calendar quarter six months after MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-2 are effective.
~~First day of the first calendar quarter that is six months beyond the date that MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-2 are effective.~~

In those jurisdictions where no regulatory approval is required, the latter of either the first day of the first calendar quarter twelve months after Board of Trustees adoption or the first day of the first calendar quarter six months after MOD-001-1, MOD-028-1, MOD-029-1 and MOD-030-2 are effective.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. The Standards Committee approved the SAR for posting on March 11, 2010.
2. The SAR was posted for industry comment from March 15, 2010 through April 29, 2010.
3. Standards Committee approved moving the project into the standards development phase on March 11, 2020.
4. The Standards Committee appointed the Standard Drafting Team on April 9, 2010.
5. The first draft of the standard was posted for a 45 day comment period on March 15, 2010.

Proposed Action Plan and Description of Current Draft:

This is the second posting of the proposed standard and its associated implementation plan for a 45-day comment period with an initial ballot conducted during the last 10 days of the comment period and ballot.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Respond to comments on the second draft of the proposed standard and the initial ballot	October 11, 2010
2. Conduct a re-circulation ballot for 10 days.	October 29, 2010
3. BOT adoption.	December, 2010

Definitions of Terms Used in Standard

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

Planning Transfer Capability (PTC): The Transfer Capability that is calculated for the planning period beyond 13 months.

Planning Transfer Capability Methodology Document (PTCMD): A document that describes the process for calculating Planning Transfer Capability (PTC).

A. Introduction

> Note: The calculation of Planning Transfer Capabilities is not meant to be a starting point for calculation of Available Transfer Capabilities or Available Flowgate Capabilities.

1. **Title:** **Planning Transfer Capability**
2. **Number:** FAC-013-2
3. **Purpose:** To ensure that Planning Coordinators calculate Planning Transfer Capabilities using an established method such that those forecasts of Transfer Capabilities are available for the reliable planning of the Bulk Electric System (BES).
4. **Applicability**

   4.1. Planning Coordinators.
5. **Effective Date:**

   In those jurisdictions where regulatory approval is required, the latter of either the first day of the first calendar quarter twelve months after applicable regulatory approval or the first day of the first calendar quarter six months after MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-2 are effective.

   In those jurisdictions where no regulatory approval is required, the latter of either the first day of the first calendar quarter twelve months after Board of Trustees adoption or the first day of the first calendar quarter six months after MOD-001-1, MOD-028-1, MOD-029-1 and MOD-030-2 are effective.

B. Requirements

R1. Each Planning Coordinator shall prepare and keep current a Planning Transfer Capability Methodology Document (PTCMD) that includes, at a minimum, the following information: [*Violation Risk Factor: Lower*] [*Time Horizon: Planning*]

1.1. A description of the assumptions and criteria used in the calculation of Planning Transfer Capabilities (PTCs) to include at a minimum how each of the following are addressed, or an explanation for any of the following not used in the calculation of PTC.

- Generation dispatch, including expected outages, additions and retirements
- Transmission system topology, including expected transmission outages, additions, and retirements
- System demand
- Current and projected transmission uses
- Parallel path impacts (loop flows)
- Contingencies
- Reliability margins applied to reflect uncertainty with BES conditions.

1.2. A list of all PTCs to be calculated.

1.3. A statement that PTCs shall respect all applicable System Operating Limits (SOLs).

1.4. A statement that the assumptions and criteria used to calculate PTCs are as, or more, limiting than the assumptions and criteria used in the operating horizon.

1.5. A description of how generation/load is adjusted to determine the PTCs identified in Requirement R1, Part 1.2.

R2. Each Planning Coordinator shall issue its PTCMD, and any revisions to the PTCMD, to the following entities prior to the effectiveness of such revisions: [*Violation Risk Factor: Lower*] [*Time Horizon: Planning*]

2.1. Each Planning Coordinator adjacent to the Planning Coordinator's planning coordinator area.

2.2. Each Transmission Planner within the Planning Coordinator's planning coordinator area.

2.3. Any other functional entity that has a reliability-related need for such PTCs and makes a written request for such PTCs.

R3. If a recipient of the PTCMD provides documented technical comments on the methodology, the Planning Coordinator shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the PTCMD and, if no change will be made to that PTCMD, the reason why. *[Violation Risk Factor: Lower][Time Horizon: Planning]*

R4. Each Planning Coordinator shall verify, and if assumptions or criteria as described in Requirement 1 Part 1.1 have changed, recalculate its PTCs consistent with its PTCMD for years two through five at least once each calendar year with no more than 15 months between verifications. [*Violation Risk Factor: Lower*] [*Time Horizon: Planning*]

R5. The Planning Coordinator shall make its PTCs available no later than 30 calendar days (following the verification or recalculation of those PTCs) to those entities identified in Requirement R2. [*Violation Risk Factor: Lower*] [*Time Horizon: Planning*]

C. Measures

M1. Each Planning Coordinator shall have a current, dated PTCMD that includes the information specified in Requirement R1.

M2. Each Planning Coordinator shall have evidence (such as dated e-mail or dated transmittal letters along with its dated new or revised PTCMD) that it issued its PTCMD and each revision to its PTCMD, to the entities specified in Requirement R2 prior to the effectiveness of such revisions.

M3. If the recipient of the PTCMD provides documented comments on its technical review of that PTCMD, the Planning Coordinator that distributed that PTCMD shall have evidence that it provided a written response to that commenter in accordance with Requirement R3.

M4. Each Planning Coordinator shall have evidence that it verified, and if necessary recalculated, its PTCs consistent with its PTCMD in accordance with Requirement R4.

M5. Each Planning Coordinator shall have evidence, such as dated copies of e-mails or transmittal letters, that it made its PTCs available to the entities listed in Requirement R5 no later than 30 calendar days following their verification or recalculation.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity.

1.2. Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.3. Data Retention

The Planning Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Planning Coordinator shall maintain its current, in force PTCMD and any prior versions of the PTCMD that were in force since the last compliance audit to show compliance with R1.
- The Planning Coordinator shall maintain evidence since its last compliance audit to show compliance with R2.
- The Planning Coordinator shall maintain evidence to show compliance with R3, R4, and R5 for the most recent calendar year plus the current year.
- If a Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time periods specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Planning Coordinator has a PTCMD but failed to address one or two of the items listed in Requirement R1, Part 1.1.	The Planning Coordinator has a PTCMD but failed to incorporate 1 of the items listed in Requirement R1, Parts 1.2 through 1.5 OR The Planning Coordinator has a PTCMD but failed to address two or more of the items listed in Requirement R1, Part 1.1.	The Planning Coordinator has a PTCMD but failed to incorporate 2 of the items listed in Requirement R1, Parts 1.2 through 1.5.	The Planning Coordinator does not have a PTCMD. OR The Planning Coordinator has a PTCMD but failed to incorporate 3 or more of the items listed in Requirement R1, Parts 1.2 through 1.5.
R2	The Planning Coordinator notified one or more of the parties specified in R2 of a new or revised PTCMD after its implementation, but not more than 30 calendar days after its implementation.	The Planning Coordinator notified one or more of the parties specified in R2 of a new or revised PTCMD more than 30 calendar days after its implementation, but not more than 40 calendar days after its implementation.	The Planning Coordinator notified one or more of the parties specified in R2 of a new or revised PTCMD more than 40 calendar days, but not more than 50 calendar days after its implementation.	The Planning Coordinator failed to notify one or more of the parties specified in R2 of a new or revised PTCMD more than 50 calendar days after its implementation.
R3	The Planning Coordinator provided a documented response to a documented technical comment as required in Requirement R3 after 45 calendar days, but not more than 60 calendar days after receipt of the comment.	The Planning Coordinator provided a documented response to a documented technical comment as required in R3 after 60 calendar days, but not more than 70 calendar days after receipt of the comment.	The Planning Coordinator provided a documented response to a documented technical comment as required in R3 after 80 calendar days after receipt of the comment.	The Planning Coordinator failed to provide a documented response to a documented technical comment as required in R3.
R4.	The Planning Coordinator failed to verify and recalculate, if necessary, 5% or less of its PTCs, as specified in the PTCMD.	The Planning Coordinator failed to verify and recalculate, if necessary, more than 5% up to and including 10% of its PTCs as specified in the PTCMD.	The Planning Coordinator failed to verify and recalculate, if necessary, more than 10% up to and including 15% of its PTCs, as specified in the PTCMD.	The Planning Coordinator failed to verify and recalculate, if necessary, more than 15% of its PTCs, as specified in the PTCMD.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R5.	The Planning Coordinator notified one or more of the parties specified in Requirement R5 of its PTCs more than 30 calendar days after their verification and recalculation, but not more than 60 calendar days after their verification and recalculation.	The Planning Coordinator notified one or more of the parties specified in Requirement R5 of its PTCs more than 60 calendar days after their verification and recalculation, but not more than 70 calendar days after their verification and recalculation.	The Planning Coordinator notified one or more of the parties specified in Requirement R5 of its PTCs more than 70 calendar days after their verification and recalculation.	The Planning Coordinator failed to notify one or more of the parties specified in Requirement R5 of its PTCs after their verification and recalculation.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
1	08/01/05	1. Changed incorrect use of certain hyphens (-) to “en dash (–).” 2. Lower cased the word “draft” and “drafting team” where appropriate. 3. Changed Anticipated Action #5, page 1, from “30-day” to “Thirty-day.” 4. Added or removed “periods.”	01/20/05
2		1. Modified to be consistent with directives contained in FERC Order 729 2. Removed Reliability Coordinator as an applicable entity	Merged FAC-012 and FAC-013 into FAC-013-2.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

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2. The SAR was posted for industry comment from March 15, 2010 through April 29, 2010.
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Proposed Action Plan and Description of Current Draft:

This is the second posting of the proposed standard and its associated implementation plan for a 45 day comment period with an initial ballot conducted during the last 10 days of the comment period. and ballot.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Respond to comments on the second draft of the proposed standard and the initial ballot	October 11, 2010
2. Conduct a re-circulation ballot for 10 days.	October 29, 2010
3. BOT adoption.	December, 2010

Definitions of Terms Used in Standard

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

Planning Transfer Capability (PTC): The ~~A forecast of the~~ Transfer Capability ~~between areas~~ that is calculated for~~used in~~ the planning period~~lanning horizon~~ beyond 13 months~~when performing planning analyses~~.

Planning Transfer Capability Methodology~~Implementation~~ Document (PTCM~~I~~D): A document that describes the ~~implementation of a~~ process~~method~~ for calculating Planning Transfer Capability (PTC)~~, and provides information related to a Planning Coordinator's calculation of PTC~~.

Note: The calculation of Planning Transfer Capabilities is not meant to be a starting point for calculation of Available Transfer Capabilities or Available Flowgate Capabilities.

A. Introduction

1. **Title:** **Planning Transfer Capability**
2. **Number:** FAC-013-2
3. **Purpose:** To ensure that Planning Coordinators calculate Planning Transfer Capabilities using an established method such that those forecasts of Transfer Capabilities are available forcan be the reliable ~~used effectively in the reliable~~ planning of the Bulk Electric System (BES).
4. **Applicability**
   4.1. Planning Coordinators.
5. **Effective Date:**

In those jurisdictions where regulatory approval is required, the latter of either the first day of the first calendar quarter twelve months after applicable regulatory approval or the first day of the first calendar quarter six months after ~~First day of the first calendar quarter that is six months beyond the date that~~ MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-2 are effective.

In those jurisdictions where no regulatory approval is required, the latter of either the first day of the first calendar quarter twelve months after Board of Trustees adoption or the first day of the first calendar quarter six months after MOD-001-1, MOD-028-1, MOD-029-1 and MOD-030-2 are effective.

B. Requirements

R1. Each Planning Coordinator shall prepare and keep current a Planning Transfer Capability Methodology~~Implementation~~ Document (~~PTCID~~PTCMD) that includes, at a minimum, the following information: [*Violation Risk Factor: Lower~~Medium~~*] [*Time Horizon: Planning*]

~~1.1. A list of all Transmission Operators for which the Planning Coordinator determines Planning Transfer Capabilities and for each of these Transmission Operators.~~

1.1. A description of the assumptions and criteria used in the calculation of Planning Transfer Capabilities (PTCs) to include at a minimum how each of the following are addressed, or an explanation for any of the following not used in the calculation of PTC.

- Generation dispatch, including expected outages, additions and retirements
- Transmission system topology, including expected transmission outages, additions, and retirements
- System demand
- Current and projected transmission uses
- Parallel path impacts (loop flows)
- Contingencies
- Reliability margins applied to reflect uncertainty with BES conditions.

1.2. A list of all PTCs to be calculated.

1.3. A statement that PTCs shall respect all applicable System Operating Limits (SOLs).

1.4. A statement that the assumptions and criteria used to calculate PTCs are as, or more, limiting than the assumptions and criteria used in the operating horizon.

1.5. A description of how generation/load is adjusted to determine the PTCs identified in Requirement R1, Part 1.2.

~~A list of the interfaces for which the Planning Coordinator determines a Planning Transfer Capability.~~

~~A detailed explanation of the methods used to calculate Planning Transfer Capabilities, including how those methods are or are not consistent with the methods selected by the Transmission Operator and described in the associated Transmission Service Provider's Available Transfer Capability Implementation Document (ATCID).~~

~~For each case in which the method used to determine a Planning Transfer Capability is not consistent with the method selected by the Transmission Operator and described in the associated Transmission Service Provider's Available Transfer Capability Implementation Document (ATCID), a justification of the inconsistency.~~

R2. Each Planning Coordinator shall issue its PTCMD, and any revisions to the PTCMD, to ~~notify~~ the following entities prior~~before~~ to the effectiveness of such revisions~~implementing a new or revised PTCID~~: [*Violation Risk Factor: Lower*] [*Time Horizon: Planning*]

2.1. Each Planning Coordinator adjacent to the Planning Coordinator's planning coordinator area.

~~2.1.~~2.2. Each Transmission Planner within the Planning Coordinator's planning coordinator area.

~~**2.2.** Each Transmission Service Provider within the Planning Coordinator's planning coordinator area.~~

~~**2.3.** Each Transmission Operator within the Planning Coordinator's planning coordinator area.~~

~~2.4.~~2.3. ~~Each Transmission Planner within the Planning Coordinator's planning coordinator area.~~Any other functional entity that has a reliability-related need for such PTCs and makes a written request for such PTCs.

R3. If a recipient of the PTC~~Methodology~~MD provides documented technical comments on the methodology, the Planning Coordinator shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the PTCM~~ethodology~~D and, if no change will be made to that PTC ~~Methodology~~MD, the reason why. *[Violation Risk Factor: Lower][Time Horizon: Planning]*

~~Each Planning Coordinator shall make available its current PTCID to all of the entities specified in Requirement R2. *[Violation Risk Factor: Lower] [Time Horizon: Planning]*~~

~~R3.~~R4. Each Planning Coordinator shall verify, and if assumptions or criteria as described in Requirement 1 Part 1.1 have changed,~~necessary~~ recalculate its PTCs consistent with its ~~PTCID~~PTCMD ~~for each season (Spring, Summer, Fall, and Winter)~~ for years two through five at least once each calendar year with no more than 15 months between verifications. [*Violation Risk Factor: Lower~~Medium~~*] [*Time Horizon: Planning*]

~~R4.~~R5. The Planning Coordinator shall make its PTCs available no later than 30~~ten~~ calendar days (following the~~ir~~ ~~being~~ verifi~~ed~~cation or ~~recalculated~~ recalculation of those PTCs) to those entities identified in Requirement R2~~:~~. [*Violation Risk Factor: Lower*] [*Time Horizon: Planning*]

~~Each Transmission Planner within the Planning Coordinator's planning coordinator area.~~

~~Any other entities specified in Requirement R2 that have a reliability-related need for such PTCs and make a written request for such PTCs.~~

C. Measures

M1. Each Planning Coordinator shall have a current, dated ~~PTCID~~PTCMD that includes the information specified in Requirement R1.

M2. Each Planning Coordinator shall have evidence (such as dated e-mail or dated transmittal letters~~phone logs~~ along with its dated new or revised ~~PTCID~~PTCMD) that it issued its PTCMD and each revision to its PTCMD, to ~~notified~~ the entities specified in Requirement R2 prior to the effectiveness of such revisions~~implementing a new or revised PTCID~~.

M3. ~~Each Planning Coordinator shall have evidence that it has made its PTCID available to the entities listed in Requirement R2.~~If the recipient of the PTCMD provides documented comments on its technical review of that PTCMD, the Planning Coordinator that distributed that PTCMD shall have evidence that it provided a written response to that commenter in accordance with Requirement R3.

M4. Each Planning Coordinator~~-~~ shall have evidence that it verified, and if necessary recalculated, its PTCs consistent with its ~~PTCID~~PTCMD in accordance with Requirement R4~~for each winter and summer season for years two through five at least once every three months~~.

M5. Each Planning Coordinator shall have evidence, such as dated copies of e-mails or transmittal letters~~dated phone logs~~, that it made its PTCs~~ID~~ available to the entities listed in Requirement R5 no later than 30~~ten~~ calendar days following their verification or recalculation.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity.

~~**1.2. Compliance Monitoring Period and Reset Time Frame**~~

~~Not applicable.~~

~~**1.3.**~~**1.2. Compliance Monitoring and Enforcement Processes:**

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

~~**1.4.**~~**1.3. Data Retention**

The Planning Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Planning Coordinator shall maintain its current, in force P~~A~~TCM~~I~~D and any prior versions of the PTCM~~I~~D that were in force since the last compliance audit to show compliance with R1.
- The Planning Coordinator shall maintain evidence since its last compliance audit to show compliance with R2.
- The Planning Coordinator shall maintain evidence to show compliance with ~~R2,~~ R3, R4, and R5 for the most recent calendar year plus the current year.
- If a Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time periods specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

~~1.5.~~1.4. Additional Compliance Information

None.

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Planning Coordinator has a ~~PTCID~~PTCMD but failed to address one or two of the items listed in Requirement R1, Part 1.1~~that does not incorporate changes made up to three months ago~~.	The Planning Coordinator has a PTCMD but failed to incorporate 1 of the items listed in Requirement R1, Parts 1.2 through 1.5 OR The Planning Coordinator has a ~~PTCID~~PTCMD but failed to address two or more of the items listed in Requirement R1, Part 1.1.~~that does not incorporate changes made three months or more but not more than six months ago.~~	The Planning Coordinator has a ~~PTCID~~PTCMD but failed to incorporate 2 of the items listed in Requirement R1, Parts 1.2 through 1.5.~~that does not incorporate changes made six months or more but not more than one year ago.~~ ~~**OR**~~ ~~The Planning Coordinator has a PTCID, and it includes some, but not all, of the items described in R1.~~	The Planning Coordinator does not have a~~has a~~ ~~PTCID~~PTCMD ~~that does not incorporate changes made a year or more ago~~. **OR** The Planning Coordinator has a ~~PTCID~~PTCMD but failed to incorporate 3 or more of the items listed in Requirement R1, Parts 1.2 through 1.5.~~, but it includes none of the items described in R1.~~ ~~**OR**~~ ~~The Planning Coordinator does not have a PTCID.~~
R2	The Planning Coordinator notified one or more of the parties specified in R2 of a new or revised~~modified~~ ~~PTCID~~PTCMD after its implementation, but not more than 30 calendar days after~~,~~ its implementation.	The Planning Coordinator notified one or more of the parties specified in R2 of a new or revised~~modified~~ ~~PTCID~~PTCMD more than 30 calendar days after its implementation, but not more than 40~~,~~ calendar days after its implementation.	The Planning Coordinator notified one or more of the parties specified in R2 of a new or revised~~modified~~ ~~PTCID~~PTCMD more than 40 calendar days, but not more than 50~~,~~ calendar days after its implementation.	The Planning Coordinator failed to notify one or more of the parties specified in R2 of a new or revised~~modified~~ ~~PTCID~~PTCMD more than 50 calendar days after its~~following its~~ implementation. ~~**OR**~~ ~~The Planning Coordinator did not notify any of the parties specified in R2 of a new or modified PTCID.~~
R3	The Planning Coordinator provided a documented response to a documented technical comment as required in Requirement R3 after 45 calendar days, but not more than 60 calendar days after receipt of the comment.~~made its PTCID available~~	The Planning Coordinator provided a documented response to a documented technical comment as required in R3 after 60 calendar days, but not more than 70 calendar days after receipt of the comment.	The Planning Coordinator provided a documented response to a documented technical comment as required in R3 after 80 calendar days after receipt of the comment.~~N/A~~	The Planning Coordinator failed to provide a documented response to a documented technical comment as required in R3.~~The Planning Coordinator made its PTCID available to none of the entities~~

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	~~to some, but not all, of the entities described in R3.~~	~~N/A~~		~~described in R3.~~
R4.	The Planning Coordinator failed to verify and recalculate, if necessary, 5% or less of its PTCs, as specified in the ~~PTCID~~PTCMD.	The Planning Coordinator failed to verify and recalculate, if necessary, more than 5% up to and including 10% of its PTCs as specified in the ~~PTCID~~PTCMD.	The Planning Coordinator failed to verify and recalculate, if necessary, more than 10% up to and including 15% of its PTCs, as specified in the ~~PTCID~~PTCMD.	The Planning Coordinator failed to verify and recalculate, if necessary, more than 15% ~~or more~~ of its PTCs, as specified in the ~~PTCID~~PTCMD.
R5.	The Planning Coordinator notified one or more of the parties specified in Requirement R5 of its PTCs more than 30 calendar days after their verification and recalculation, but not more than 60 calendar days after their verification and recalculation.~~The Planning Coordinator made the PTCs available to some, but not all, of the entities described in R5, Part 5.2.~~	The Planning Coordinator notified one or more of the parties specified in Requirement R5 of its PTCs more than 60 calendar days after their verification and recalculation, but not more than 70 calendar days after their verification and recalculation.~~The Planning Coordinator made the PTCs available to none of the entities described in R5, Part 5.2.~~	The Planning Coordinator notified one or more of the parties specified in Requirement R5 of its PTCs more than 70 calendar days after their verification and recalculation.~~The Planning Coordinator made the PTCs available to some, but not all, of the entities described in R5, Part 5.1~~.	The Planning Coordinator failed to notify one or more of the parties specified in Requirement R5 of its PTCs after their verification and recalculation.~~The Planning Coordinator made the PTCs available to none of the entities described in R5, Part 5.1.~~

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
1	08/01/05	1. Changed incorrect use of certain hyphens (-) to "en dash (–)." 2. Lower cased the word "draft" and "drafting team" where appropriate. 3. Changed Anticipated Action #5, page 1, from "30-day" to "Thirty-day." 4. Added or removed "periods."	01/20/05
2		1. Modified to be consistent with directives contained in FERC Order 729 2. Removed Reliability Coordinator as an applicable entity	Merged FAC-012 and FAC-013 into FAC-013-2.

Standards Announcement

Ballot Pool Formation September 20-October 20, 2010
Formal Comment Period September 20-November 3, 2010
Project 2010-10 — FAC-013 Order 729

Now available at: http://www.nerc.com/filez/standards/Project2010-10_FAC_Order_729.html

Project 2010-10 — FAC Order 729

In Order 729, FERC ruled that the ATC standards developed in Project 2006-07 did not completely address the topics covered in FAC-012 and -013 and did not fully address the associated directives from Order 693. Accordingly, FERC denied the portions of the implementation plan that would have retired these standards, and instead directed NERC to use the standards development process to make changes to the FAC standards and file those changes with FERC no later than 60 days prior to the effective date of the standards, which is April 1, 2011 (requiring the proposed changes to be filed on or before January 31, 2011).

A second draft of the proposed standard has been developed that attempts to address the applicable FERC directives (listed in the SAR) as well as to address concerns raised by the industry during the first posting.

Ballot Pool Open through 0900 a.m. on October 20, 2010

Registered Ballot Body members may join the ballot pool **until 8 a.m. Eastern on October 20, 2010** to be eligible to vote in the upcoming ballot for the FAC-013-1 — Planning Transfer Capability at the following page: https://standards.nerc.net/BallotPool.aspx

Members who join the ballot pool to vote on the standard will automatically be entered in a separate pool to participate in the non-binding poll of the associated violation risk factors (VRFs) and violation severity levels (VSLs).

During the pre-ballot window, members of the ballot pool may communicate with one another by using their "ballot pool list server." (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list server.) The list server for this ballot pool is: bp-2010-10_FAC-013-2_in

Formal 45-day Comment Period Open through November 3, 2010

Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Monica Benson at monica.benson@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page:

http://www.nerc.com/filez/standards/Project2010-10_FAC_Order_729.html

Transition from Reliability Standards Development Procedure Version 7 to Standard Processes Manual

Under the Reliability Standards Development Procedure Version 7, consensus was built with successive formal comment periods, followed by a 30-day pre-ballot review, followed by an initial ballot, and then a recirculation ballot. The intent was to use stakeholder views submitted through the formal comment periods to achieve consensus, and then to confirm that consensus during the balloting. This process did not allow a drafting team to make any changes to a standard between ballots, which incented teams to avoid making improvements once a standard had gone through an initial ballot. If a team made a change between ballots, then the standard was required to be posted for a new comment period, followed by another pre-ballot review and a new initial ballot. Finally, if there were no more changes made to the standard, a recirculation ballot was conducted to confirm consensus.

Under the new Standard Processes Manual, consensus is achieved through parallel comment and ballot periods. Successive comment and ballot periods are conducted until there is consensus – and then a recirculation ballot is conducted to confirm that consensus. There is no 30-day pre-ballot review period, and drafting teams are encouraged to make revisions to the standard between successive ballots to improve the quality of the standard.

Next Steps

During the last 10 days of the 45-day formal comment period an initial ballot and a non-binding poll of opinions on the VRFs and VSLs will both be conducted.

Project Background

The purpose of this project is to address FERC directives from Order 729 related to FAC-012-1 and FAC-013-1. The drafting team for Project 2006-07 (ATC/TTC/AFC and CBM/TRM Revisions) proposed the retirement of FAC-012 and FAC-013, believing that these standards had been effectively superseded by four standards developed in the project (MOD-001, MOD-028, MOD-029, and MOD-030). In Order 729, FERC ruled that the standards developed in Project 2006-07 did not completely address the topics covered in FAC-012 and FAC-013, and did not fully address the associated directives from Order 693. Accordingly, FERC denied the portions of the implementation plan that would have retired these standards, and directed NERC to use the standards development process to make changes to the FAC standards, and file those changes with FERC no later than 60 days prior to the effective date of the standards approved in Order 729.

Applicability of Standard in Project

Planning Coordinator

For more information or assistance, please contact Monica Benson,
Standards Process Administrator, at monica.benson@nerc.net or at 609.452.8060

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NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Initial Ballot Window Open
October 20-November 3, 2010

Now available at: https://standards.nerc.net/CurrentBallots.aspx

Project 2010-10 — FAC Order 729

An initial ballot window for standard FAC-013-2 – Planning Transfer Capability is open **until 8 p.m. Eastern on November 3, 2010**.

In addition, members of this ballot pool will be able to vote in a concurrent non-binding poll on the standard's Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs). Members who joined the ballot pool to vote on the standard were automatically entered in a separate pool to participate in the non-binding poll for the VRFs and VSLs. The non-binding poll will appear in the list of current ballots, and is labeled accordingly.

Note that FAC-013-2 reflects the merging of the following standards into a single standard, making it impractical to post a "redline" of proposed FAC-013-2 that shows the changes to the last balloted version of the standard. For stakeholders who want to see the last approved versions of FAC-012-1, and FAC-013-1, these have been posted on the FAC Order 729 project page for easy reference.

- FAC-012-1 – Transfer Capability Methodology
- FAC-013-1 – Establish and Communicate Transfer Capabilities

Instructions

Members of the ballot pools associated with this project may log in and submit their votes from the following page: https://standards.nerc.net/CurrentBallots.aspx

Transition from Reliability Standards Development Procedure Version 7 to Standard Processes Manual

Under the Reliability Standards Development Procedure Version 7, consensus was built with successive formal comment periods, followed by a 30-day pre-ballot review, followed by an initial ballot, and then a recirculation ballot. The intent was to use stakeholder views submitted through the formal comment periods to achieve consensus, and then to confirm that consensus during the balloting. This process did not allow a drafting team to make any changes to a standard between ballots, which incented teams to avoid making improvements once a standard had gone through an initial ballot. If a team made a change between ballots, then the standard was required to be posted for a new comment period, and then another pre-ballot review and another initial ballot. Finally, if there were no more changes made to the standard, a recirculation ballot was conducted to confirm consensus.

Under the new Standard Processes Manual, consensus is achieved through parallel comment and ballot periods. Successive comment and ballot periods are conducted until there is consensus – and then a recirculation ballot is conducted to confirm that consensus. There is no 30-day pre-ballot review period, and drafting teams are encouraged to make revisions to the standard between successive ballots to improve the quality of the standard.

Next Steps

The drafting team will consider all comments (those submitted with a comment form, and those submitted with a ballot) and will determine whether to make additional changes to the standard. The team will post the initial ballot results and its response to comments.

- If the standard needs significant modifications, the team will post the revised standard for a new 30-day comment period and will conduct a new ballot (called a "successive" ballot) during the last 10 days of that comment period. The team will post its response to all comments, and then proceed (if the standard needs no significant changes) to a recirculation ballot. During a successive ballot all members of the ballot pool must cast a new ballot, as the standard presented has significant changes.
- If the initial ballot and parallel comment period show that the standard needs either minor or no changes, the team will post the standard and conduct a 10-day recirculation ballot. During a recirculation ballot members of the ballot pool may cast a new vote but are not required to do so as the standard presented does not have any significant changes.

Project Background

In Order 729, FERC ruled that the ATC standards developed in Project 2006-07 did not completely address the topics covered in FAC-012 and -013 and did not fully address the associated directives from Order 693. Accordingly, FERC denied the portions of the implementation plan that would have retired these standards, and instead directed NERC to use the standards development process to make changes to the FAC standards and file those changes with FERC no later than 60 days prior to the effective date of the standards, which is April 1, 2011 (requiring the proposed changes to be filed on or before January 31, 2011).

A second draft of the proposed standard has been developed that attempts to address the applicable FERC directives (listed in the SAR) as well as to address concerns raised by the industry during the first posting.

Applicability of Standards in Project

Planning Coordinators

Standards Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Monica Benson,
Standards Process Administrator, at monica.benson@nerc.net or at 609.452.8060.

Consideration of Comments on Modifications to FAC-012 and FAC-013 for Order 729 Draft FAC-013-2 Standard — Project 2010-10

The Modifications to FAC-012 and FAC-013 for Order 729 - Draft FAC-013-2 Standard Drafting Team thanks all commenters who submitted comments on the SAR and modifications proposed FAC-013-2 — Planning Transfer Capability. These standards were posted for a 45-day public comment period from September 20, 2010 through November 3, 2010. The stakeholders were asked to provide feedback on the standards through a special Electronic Comment Form. There were 33 sets of comments, including comments from more than 98 different people from approximately 75 companies representing 10 of the 10 Industry Segments as shown in the table on the following pages.

Based on the comments received the drafting team made the following changes to the proposed Standard:

- Removed the definitions of Planning Transfer Capability (PTC) and Planning Transfer Capability Methodology Document (PTCMD).
- Modified the Purpose Statement to clarify that the that Planning Coordinators need to develop a methodology for, and perform an annual assessment of, Transfer Capabilities in the Near-Term Transmission Planning Horizon that are needed for reliable planning
- Modified Requirement R1 to provide further clarity.
- Added a requirement to obligate Planning Coordinators, upon request, to provide data to support the assessment results.
- Modified the Measures to better align with the Requirements.
- Modified the VSLs to align with the modifications to the Requirements.

In this "Consideration of Comments" document stakeholder comments have been organized so that it is easier to see the responses associated with each question. All comments received on the standards can be viewed in their original format at:

http://www.nerc.com/filez/standards/Project2010-10_FAC_Order_729.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Herb Schrayshuen, at 609-452-8060 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Standard Processes Manual.

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Gregory Campoli	New York Independent System Operator	NPCC	2
3.	Kurtis Chong	Independent Electricity System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Dean Ellis	Dynegy Generation	NPCC	5
8.	Brian Evans-Mongeon	Utility Services	NPCC	8
9.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
10.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5
11.	Kathleen Goodman	ISO - New England	NPCC	2
12.	Chantel Haswell	FPL Group, Inc.	NPCC	5
13.	David Kiguel	Hydro One Networks Inc.	NPCC	1
14.	Michael R. Lombardi	Northeast Utilities	NPCC	1

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

15.	Randy MacDonald	New Brunswick System Operator	NPCC	2
16.	Bruce Metruck	New York Power Authority	NPCC	6
17.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
18.	Robert Pellegrini	The United Illuminating Company	NPCC	1
19.	Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
20.	Saurabh Saksena	National Grid	NPCC	1
21.	Michael Schiavone	National Grid	NPCC	1
22.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

				1	2	3	4	5	6	7	8	9	10
2.	Group	Philip R. Kleckley	SERC Planning Standards Subcommittee	X		X		X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Sullivan	Ameren Services Company	SERC	1
2.	Charles Long	Entergy	SERC	1
3.	Jim Kelley	PowerSouth Energy Cooperative	SERC	1
4.	Bob Jones	Southern Company Services, Inc. - Trans.	SERC	1
5.	Pat Huntley	SERC Reliability Corporation	SERC	10

				1	2	3	4	5	6	7	8	9	10
3.	Group	Denise Koehn	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Laura Trolese	BPA, Transmission, Policy Development & Analysis	WECC	1
2.	Kyle Kohne	BPA, Transmission, Planning	WECC	1
3.	James Randall	BPA, Transmission, Planning	WECC	1
4.	Rebecca Berdahl	BPA, Power, Long Term Sales and Purchases	WECC	3

				1	2	3	4	5	6	7	8	9	10
4.	Group	Ben Li	IRC Standards Review Committee		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Patrick Brown	PJM	RFC	2
2.	Matthew Goldberg	ISO NE	NPCC	2
3.	Greg Campoli	NY ISO	NPCC	2

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
4.	Mark Tompson	AESO	WECC	2
5.	Charles Yeung	SPP	SPP	2
6.	Steve Myers	ERCOT	ERCOT	2
7.	Bill Phillips	MISO	RFC	2
8.	Matt Morias	ERCOT	ERCOT	2
9.	Kathleen Goodman	ISO NE	NPCC	2
10.	Jason Marshall	MISO	RFC	2
11.	Albert DiCaprio	PJM	RFC	2

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5.	Group	Carol Gerou	MRO's NERC Standards Review Subcommittee										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mahmood Safi	Omaha Public Utility District	MRO	1, 3, 5, 6
2.	Chuck Lawrence	American Transmission Company	MRO	1
3.	Tom Webb	WPS Corporation	MRO	3, 4, 5, 6
4.	Jason Marshall	Midwest ISO Inc.	MRO	2
5.	Jodi Jenson	Western Area Power Administration	MRO	1, 6
6.	Ken Goldsmith	Alliant Energy	MRO	4
7.	Alice Murdock	Xcel Energy	MRO	1, 3, 5, 6
8.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
9.	Eric Ruskamp	Lincoln Electric System	MRO	1, 3, 5, 6
10.	Joseph Knight	Great River Energy	MRO	1, 3, 5, 6
11.	Joe DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6
12.	Scott Nickels	Rochester Public Utilties	MRO	4
13.	Terry Harbour	MidAmerican Energy Company	MRO	1, 3, 5, 6

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Group	Paul Allen	Tampa Electric Company	X		X		X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jorge Haylock		FRCC	1, 3, 5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2. Beth Young			FRCC 1, 3, 5										
3. Jose Quintas			FRCC 1, 3, 5										
7.	Group	W. R. Schoneck	FPL Transmission Planning	X		X							

Additional Member	Additional Organization	Region	Segment Selection
1.	John W. Shaffer	FPL	FRCC
2.	Kiko Barredo	FPL	FRCC

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	Frank Gaffney	Florida Municipal Power Agency	X		X	X	X	X	X			

Additional Member	Additional Organization	Region	Segment Selection	
1.	Timothy Beyrle	Utilities Commission, City of New Smyrna Beach	FRCC	4
2.	Greg Woessner	Kissimmee Utility Authority	FRCC	3
3.	Jim Howard	Lakeland Electric	FRCC	3
4.	Lynne Mila	City of Clewiston	FRCC	3
5.	Joe Stonecipher	Beaches Energy Services	FRCC	1
6.	Cairo Vanegas	Fort Pierce Utility Authority	FRCC	4

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Individual	Randall McCamish	FMPA	X		X							
10.	Individual	Brent Ingebrigtson	LG&E and KU Energy LLC	X		X		X	X				
11.	Individual	Andy Tillery	Southern Company	X		X							
12.	Individual	JC Culberson	ERCOT		X								
13.	Individual	Ross Kovacs	Georgia Transmission Corporation	X									
14.	Individual	Greg Rowland	Duke Energy	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
15.	Individual	Darrin Adams	East Kentucky Power Cooperative, Inc.	X		X		X					
16.	Individual	Kasia Mihalchuk	Manitoba Hydro	X		X		X	X				
17.	Individual	Jonathan Appelbaum	United Illuminating	X									
18.	Individual	Aaron Staley	Orlando Utilities Commission	X									
19.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
20.	Individual	Bob Easton	WAPA-RMR	X								X	
21.	Individual	Steve Rueckert	WECC										X
22.	Individual	Kathleen Goodman	ISO New England Inc.		X								
23.	Individual	Andrew Z. Pusztai	American Transmission Company	X									
24.	Individual	Jason Marshall	Midwest ISO		X								
25.	Individual	John Bussman	AECI	X		X		X	X				
26.	Individual	Dan Rochester	Independent Electricity System Operator		X								
27.	Individual	J. S. Stonecipher, PE	Beaches Energy Services (of the City of Jacksonville Beach, FL)	X								X	
28.	Individual	Darcy O'Connell	California ISO		X								
29.	Individual	Laurie Williams	PNMR	X		X							

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
30.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				
31.	Individual	Bart White	Progress Energy Florida	X		X		X	X				
32.	Individual	Dennis Chastain	Tennessee Valley Authority	X		X		X	X				
33.	Individual	Michael Gammon	Kansas City Power & Light	X		X		X	X				

1. The SDT has modified the definition of Planning Transfer Capability (PTC). The definition now reads "The Transfer Capability that is calculated for the planning period beyond 13 months." Do you agree that the revised definition provides additional clarity as to the time period for the calculations?

Summary Consideration: Although many stakeholders agreed that the revisions to the definition of the term Planning Transfer Capability provided additional clarity, several commenters felt that the new term was not necessary or needed additional clarity as to whether the term was defining the total amount available or the incremental amount available. The SDT responded to the stakeholders by removing the proposed term. The SDT also explained that the standard's emphasis was on assessment of future reliability and facilities that may be impacted by changes in power transfers, not specific transfer capability values. In addition, the SDT explained that the concept of a transfer capability assessment in the Near-Term Planning Horizon had been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon.

Organization	Yes or No	Question 1 Comment
Northeast Power Coordinating Council	No	The creation of a new term is not necessary. ATC and TTC should be used.
Response: The SDT agrees and has dropped the term. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values. The industry does not support calculation of ATC beyond the operating horizon.		
ISO New England Inc.	No	The creation of a new term is unnecessary. ATC and TTC should be utilized.
Response: The SDT agrees and has dropped the term. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values. The industry does not support calculation of ATC beyond the operating horizon.		
Florida Municipal Power Agency	No	It is unclear whether PTC is allegorical to TTC or to ATC. The term should be modified to clarify whether PTC is the total or the incremental available. Without this clarity, on PC might calculate a total whereas its neighboring PC calculate an incremental available value and the numbers will be dramatically different causing confusion. Also, it leaves the values of PTC open to interpretation.FMPA recommends that PTC be calculated as the total; however, the PC should also report the TRM, CBM and existing long term firm commitments assumed so that entities understand that the total may not all be available (e.g., in the PTCMD).
Response: The PTC definition has been deleted based on industry comments and the concept of transfer capability assessment in the Near-Term Planning		

Organization	Yes or No	Question 1 Comment
Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values.		
FMPA	No	It is unclear whether PTC is allegorical to TTC or to ATC. The term should be modified to clarify whether PTC is the total or the incremental available. Without this clarity, on PC might calculate a total whereas its neighboring PC calculate an incremental available value and the numbers will be dramatically different causing confusion. Also, it leaves the values of PTC open to interpretation.FMPA recommends that PTC be calculated as the total; however, the PC should also report the TRM, CBM and existing long term firm commitments assumed so that entities understand that the total may not all be available (e.g., in the PTCMD).
Response: The PTC definition has been deleted based on industry comments and the concept of transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values.		
Beaches Energy Services (of the City of Jacksonville Beach, FL)	No	It is unclear whether PTC is allegorical to TTC or to ATC. The term should be modified to clarify whether PTC is the total or the incremental available. Without this clarity, on PC might calculate a total whereas its neighboring PC calculate an incremental available value and the numbers will be dramatically different causing confusion. Also, it leaves the values of PTC open to interpretation.Beaches Energy Services (BES) recommends that PTC be calculated as the total; however, the PC should also report the TRM, CBM and existing long term firm commitments assumed so that entities understand that the total may not all be available (e.g., in the PTCMD).
Response: The PTC definition has been deleted based on industry comments and the concept of transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values.		
Independent Electricity System Operator	No	We continue to disagree with the need to define these terms. A review of the Comment Report also suggests that the majority of the commenters disagree with the need to define these terms. We are disappointed that the SDT chose to ignore the majority comments.Our previous comments suggested that the term PTC does not provide any material difference than the term Transfer Capability, which has been defined and adopted for a long period of time. The industry is familiar with this definition, and has a deep and unambiguous understanding that in general term, it is the attainable level of power transfer from one point to another or on a specific transmission path. The proposed definition for PTC is redundant and trivial since it still uses Transfer Capability as a defined term, with additional wording to indicate it is calculated for the planning period only. We believe this distinction can be achieved simply by insetting the phrase "in the planning period" to the term Transfer Capability in the appropriate requirements of the standard. Creating additional definitions require

Organization	Yes or No	Question 1 Comment
		additional maintenance of the glossary, and may create conflicting understanding for the same terms defined in different jurisdiction and documents (e.g. regional standards, legislation, etc.), and is to be avoided if words in the standards can convey the same intent/meaning.
Response: The PTC definition has been deleted based on industry comments and the concept of a transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The time period applicable to the assessment has been identified as the Near-Term Transmission Planning Horizon in the body of the requirements. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values. No new definitions are necessary.		
Xcel Energy	No	Xcel Energy continues to disagree with the need to create the term Planning Term Capability (PTC) for essentially the same reasons cited in our comments to the previous posting, that is, the existing glossary terms "Transfer Capability" and "Total Transfer Capability" are more than sufficient for the purposes of this standard. The proposed modified definition of PTC intends to clarify the time horizon to which the Transfer Capability applies - we do not see the need and/or value of a new glossary term simply to clarify that the applicability of Transfer Capability in the context of this standard is for the planning time horizon. Further, we are not persuaded by SDT's assertion that PTC is "necessary to avoid confusion with other forms of transfer capability (i.e. TTC and ATC) that have a different meaning and purpose." in its response to the vast majority of commenters in the previous posting (First Energy, Bonneville Power Administration, Independent Electricity System Operator, IRS Standards Review Committee, Northeast Power Coordinating Council, Ameren, Midwest ISO Stakeholders) who commented that the existing terms Transfer Capability and Total Transfer Capability are well established, well understood and adequate. Please note that the existing definitions of TC and TTC are both a measure of electric power that can be reliably moved or transferred between areas *under specified system conditions* -- we do not see how this precludes the computation of TTC or TC for planning horizon system conditions.
Response: The PTC definition has been deleted based on industry comments and the concept of a transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon.. The time period applicable to the assessment has been identified as the Near-Term Transmission Planning Horizon in the body of the requirements. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values.		
PNMR	No	NERC has done a poor job of addressing the confusion over TTC, PTC and System Operating Limits, and the difference between the concepts and reliability concerns addressed by FAC-010, FAC-014, the proposed FAC-013-2 and the MOD standards. As written, the proposed 13.2 just adds to this confusion. Transfer Capability should not be a term with different potential meaning between standards because of the period (planning versus operating) or use multiple phrases for the same quantity like SOL and transfer capability. NERC needs to step back and address clarifications on the terminology and concepts in existing standards

Organization	Yes or No	Question 1 Comment
		before any new standards on transfer capability methodology are approved. There are various terms used that are inconsistent between documents and need to be clarified (like "path" as used in R1 1.1 vs ATC path", "SOL" vs "transfer capability" vs "path rating") and the relationship of the standards needs to be clear and not duplicative.The note in the introduction indicates that PTC "is not meant to be a starting point for calculation of" ATC. What is the starting point for calculation of available transmission capacity in the planning horizon? Reference to "any System Operating Limit" is made in MOD-029 yet the SOL Methodology only applies to the planning horizon while MOD-029 only applies to the Operations Planning horizon. How can a concept that only applies within one time-frame be used in a mutually exclusive other time-frame? The implied overlap of the proposed FAC13.2 between the MOD standards and FAC-010 indicates that FAC 13-2 is duplicative, unnecessary and confusing.
Response: The PTC definition has been deleted based on industry comments and the concept of transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The SDT does not believe there is an overlap between the revised draft and the MOD standards and FAC-010. These deal with calculation of ATC/AFC and identification of SOL's. The FAC-013 standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values nor defining SOL's.		
ERCOT	Yes	The definition adds clarity regarding the time period for the calculations, but does not indicate the use of such calculated values. Available Transfer Capability ("ATC") may be calculated in response to specific transmission service requests that extend beyond the time horizon covered by the MOD standards. First Contingency Incremental Transfer Capability ("FCITC") may also be calculated during studies performed by Planning Coordinators. When the references to the MOD standards are considered, the applicability of the definition is unclear with regard to these two concepts.
Response: The PTC definition has been deleted based on industry comments and the concept of transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The time period applicable to the assessment has been identified as the Near-Term Transmission Planning Horizon in the body of the requirements. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values.		
American Transmission Company	Yes	The definition adds clarity regarding the time period for the calculations, but does not indicate the use of such calculated values. Available Transfer Capability ("ATC") may be calculated in response to specific transmission service requests that extend beyond the time horizon covered by the MOD standards. First Contingency Incremental Transfer Capability ("FCITC") may also be calculated during studies performed by Planning Coordinators. When the references to the MOD standards are considered, the applicability of the definition is unclear with regard to these two concepts.

Organization	Yes or No	Question 1 Comment
Response: The PTC definition has been deleted based on industry comments and the concept of transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The time period applicable to the assessment has been identified as the Near-Term Transmission Planning Horizon in the body of the requirements. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values.		
Midwest ISO	Yes	The definition adds clarity regarding the time period for the calculations, but does not indicate the use of such calculated values. Available Transfer Capability ("ATC") may be calculated in response to specific transmission service requests that extend beyond the time horizon covered by the MOD standards. First Contingency Incremental Transfer Capability ("FCITC") may also be calculated during studies performed by Planning Coordinators. When the references to the MOD standards are considered, the applicability of the definition is unclear with regard to these two concepts.
Response: The PTC definition has been deleted based on industry comments and the concept of a transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The time period applicable to the assessment has been identified as the Near-Term Transmission Planning Horizon in the body of the requirements. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values.		
California ISO	Yes	The definition adds clarity regarding the time period for the calculations, however does not indicate the use or value of such calculations. We ask the SDT to explain what the difference is between PTCs and SOLs in the planning horizon. Calculation of PTCs appears to be duplicative of the calculation of SOLs in the planning horizon, and therefore duplicative with other existing NERC standards.
Response: The PTC definition has been deleted based on industry comments and the concept of a transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values nor defining SOLs.		
Kansas City Power & Light	Yes	The definition adds clarity regarding the time period for the calculations, but does not indicate the use of such calculated values. Available Transfer Capability ("ATC") may be calculated in response to specific transmission service requests that extend beyond the time horizon covered by the MOD standards. First Contingency Incremental Transfer Capability ("FCITC") may also be calculated during studies performed by Planning Coordinators. When the references to the MOD standards are considered, the applicability of the definition is unclear with regard to these two concepts.
Response: The PTC definition has been deleted based on industry comments and the concept of a transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The time period		

Organization	Yes or No	Question 1 Comment
applicable to the assessment has been identified as the Near-Term Transmission Planning Horizon in the body of the requirements. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values.		
IRC Standards Review Committee	Yes	The definition adds clarity regarding the time period for the calculations, but does not indicate the use of such calculated values. Available Transfer Capability ("ATC") may be calculated in response to specific transmission service requests that extend beyond the time horizon covered by the MOD standards. First Contingency Incremental Transfer Capability ("FCITC") may also be calculated during studies performed by Planning Coordinators. When the references to the MOD standards are considered, the applicability of the definition is unclear with regard to these two concepts.
Response: The PTC definition has been deleted based on industry comments and the concept of transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The time period applicable to the assessment has been identified as the Near-Term Transmission Planning Horizon in the body of the requirements. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values.		
Tennessee Valley Authority	Yes	The revised definition of PTC does provide additional clarity as to the begin point of the intended time period. Transfer Capability is also calculated for time periods within the 13 month window for pre-seasonal operations planning studies. Is there a separate project / Standard Drafting Team addressing this time frame?
Response: The PTC definition has been deleted based on industry comments and the concept of transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The time period applicable to the assessment has been identified as the Near-Term Transmission Planning Horizon in the body of the requirements. The 13 month window is addressed by MOD-001, -028, 029 and -030.		
Bonneville Power Administration	Yes	The definition provides clarity as to the time period for the calculations. However, the purpose and need for calculating PTCs is still unclear. See comment in Question 8.
Response: The PTC definition has been deleted based on industry comments and the concept of transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The time period applicable to the assessment has been identified as the Near-Term Transmission Planning Horizon in the body of the requirements. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values.		
MRO's NERC Standards Review Subcommittee	Yes	The definition adds clarity regarding the time period for the calculations, but does not indicate the use of such calculated values. Available Transfer Capability ("ATC") may be calculated in response to specific transmission service requests that extend beyond the time horizon covered by the MOD standards. First Contingency Incremental Transfer Capability ("FCITC") may also be calculated during studies performed by

Organization	Yes or No	Question 1 Comment
		Planning Coordinators. When the references to the MOD standards are considered, the applicability of the definition is unclear with regard to these two concepts.
Response: The PTC definition has been deleted based on industry comments and the concept of a transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The time period applicable to the assessment has been identified as the Near-Term Transmission Planning Horizon in the body of the requirements. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values.		
Georgia Transmission Corporation	Yes	
AECI	Yes	
United Illuminating	Yes	
Orlando Utilities Commision	Yes	
South Carolina Electric and Gas	Yes	
WAPA-RMR	Yes	
Duke Energy	Yes	
East Kentucky Power Cooperative, Inc.	Yes	
Manitoba Hydro	Yes	
Tampa Electric Company	Yes	
FPL Transmission Planning	Yes	
Progress Energy Florida	Yes	
Southern Company	Yes	

Organization	Yes or No	Question 1 Comment
SERC Planning Standards Subcommittee	Yes	
WECC		The revised definition clarifies the time period for the calculations of PTC. However, the purpose and need for calculationg PTCs is unclear. What is the difference between an SOL for the Planning horizon and a PTC that must respect all SOLs. It appears that in the end one would end up with the same value. Please provide an example of how an SOL and a PTC differ.
Response: The PTC definition has been deleted based on industry comments and the concept of a transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values nor defining SOLs.		

2. The SDT has modified the definition of Planning Transfer Capability Implementation Document (PTCID) so that it is now called Planning Transfer Capability Methodology Document (PTCMD). The definition now reads "A document that describes the process for calculating Planning Transfer Capability (PTC)." Do you agree that the revised definition provides additional clarity as to the purpose of the document?

Summary Consideration: The majority of negative commenters were confused as to the intent of the Planning Transfer Capability Methodology Document. The SDT explained that the PTC and PTCMD definitions had been deleted based on industry comments and the concept of a transfer capability assessment in the Near-Term Planning Horizon had been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. Further, the standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers, not specific transfer capability values.

Organization	Yes or No	Question 2 Comment
IRC Standards Review Committee	No	The development of the PTCMD, as described in the standard, creates confusion as to whether the PTCMD is intended to describe: (1) the entity's methodology for continued calculation of ATC for the 2 to 5 year horizon as such values would be calculated in response to specific transmission service requests or (2) the entity's methodology for calculation of FCITC in the 2 to 5 year horizon. Clarity as to the applicability and scope for which the PTCMD is intended is critical for compliance with this standard as ATC and FCITC are calculated differently for different purposes. Currently, Reliability Coordinators calculate FCITC in the operating horizon in the seasonal pre-summer and pre-winter operating studies or seasonal assessments in accordance with the current, approved standards FAC-012-1 and FAC-013-1. The MOD standards were approved by the Federal Energy Regulatory Commission ("FERC") in Order 729 as the standards applicable to calculating transfer capabilities in the Operating Horizon, which ATC values are utilized for the sale of transmission service. In Order 729 (Â¶ 289), FERC required NERC to modify FAC-012 and FAC-013 such that those standards would require and be the applicable standards for calculation of transfer capability values for the Planning Horizon and such that the criteria used for calculations would be "identical" between the planning and operating horizons. Hence, it is not clear if the intention of this standard and the PTCMD is to describe an entity's methodology for calculation of ATC values for the Planning Horizon or, rather, if the intention of this standard and the PTCMD is to describe an entity's methodology for calculation of FCITC values for the Planning Horizon. Additional, detailed comments are provided under question 3 (R1.1 & R1.1.4) below.
Response: The standard has been clarified to be applicable to the Near-Term Transmission Planning Horizon. The PTC and PTCMD definitions have been deleted based on industry comments and the concept of atransfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The standard's emphasis is on assessment of future reliability and		

Organization	Yes or No	Question 2 Comment
facilities that may be impacted by changes in transfers - not specific transfer capability values.		
MRO's NERC Standards Review Subcommittee	No	The development of the PTCMD, as described in the standard, creates confusion as to whether the PTCMD is intended to describe: (1) the entity's methodology for continued calculation of ATC for the 2 to 5 year horizon as such values would be calculated in response to specific transmission service requests or (2) the entity's methodology for calculation of FCITC in the 2 to 5 year horizon. Clarity as to the applicability and scope for which the PTCMD is intended is critical for compliance with this standard as ATC and FCITC are calculated differently for different purposes. Currently, Reliability Coordinators calculate FCITC in the operating horizon in the seasonal pre-summer and pre-winter operating studies or seasonal assessments in accordance with the current, approved standards FAC-012-1 and FAC-013-1. The MOD standards were approved by the Federal Energy Regulatory Commission ("FERC") in Order 729 as the standards applicable to calculating transfer capabilities in the Operating Horizon, which ATC values are utilized for the sale of transmission service. In Order 729 (Â¶ 289), FERC required NERC to modify FAC-012 and FAC-013 such that those standards would require and be the applicable standards for calculation of transfer capability values for the Planning Horizon and such that the criteria used for calculations would be "identical" between the planning and operating horizons. Hence, it is not clear if the intention of this standard and the PTCMD is to describe an entity's methodology for calculation of ATC values for the Planning Horizon or, rather, if the intention of this standard and the PTCMD is to describe an entity's methodology for calculation of FCITC values for the Planning Horizon. Additional, detailed comments are provided under question 3 (R1.1 & R1.1.4) below.
Response: The standard has been clarified to be applicable to the Near-Term Transmission Planning Horizon. The PTC and PTCMD definitions have been deleted based on industry comments and the concept of a transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values.		
ERCOT	No	The development of the PTCMD, as described in the standard, creates confusion as to whether the PTCMD is intended to describe: (1) the entity's methodology for continued calculation of ATC for the 2 to 5 year horizon as such values would be calculated in response to specific transmission service requests or (2) the entity's methodology for calculation of FCITC in the 2 to 5 year horizon. Clarity as to the applicability and scope for which the PTCMD is intended is critical for compliance with this standard as ATC and FCITC are calculated differently for different purposes. Currently, Reliability Coordinators calculate FCITC in the operating horizon in the seasonal pre-summer and pre-winter operating studies or seasonal assessments in accordance with the current, approved standards FAC-012-1 and FAC-013-1. The MOD standards were approved by the Federal Energy Regulatory Commission ("FERC") in Order 729 as the standards applicable to calculating transfer capabilities in the Operating Horizon, which ATC values are utilized for the sale of transmission service. In Order 729 (Â¶ 289), FERC required NERC to modify FAC-012 and FAC-013 such

Organization	Yes or No	Question 2 Comment
		that those standards would require and be the applicable standards for calculation of transfer capability values for the Planning Horizon and such that the criteria used for calculations would be “identical” between the planning and operating horizons. Hence, it is not clear if the intention of this standard and the PTCMD is to describe an entity’s methodology for calculation of ATC values for the Planning Horizon or, rather, if the intention of this standard and the PTCMD is to describe an entity’s methodology for calculation of FCITC values for the Planning Horizon. Additional, detailed comments are provided under question 3 (R1.1 & R1.1.4) below.Absent a transmission service market, transfer capabilities are not applicable; therefore, there would be no benefit in developing a PTCMD.
Response: The standard has been clarified to be applicable to the Near-Term Transmission Planning Horizon. The PTC and PTCMD definitions have been deleted based on industry comments and the concept of a transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The standard’s emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values. Transfers occur between all areas, even non-market areas – the SDT does not understand the basis for this comment.		
American Transmission Company	No	The development of the PTCMD, as described in the standard, creates confusion as to whether the PTCMD is intended to describe: (1) the entity’s methodology for continued calculation of “ATC” for the 2 to 5 year horizon as such values would be calculated in response to specific transmission service requests or (2) the entity’s methodology for calculation of FCITC in the 2 to 5 year horizon. Clarity as to the applicability and scope for which the PTCMD is intended is critical for compliance with this standard as “ATC” and FCITC are calculated differently for different purposes. Currently, Reliability Coordinators calculate FCITC in the operating horizon in the seasonal pre-summer and pre-winter operating studies or seasonal assessments in accordance with the current, approved standards FAC-012-1 and FAC-013-1. The MOD standards were approved by the Federal Energy Regulatory Commission (“FERC”) in Order 729 as the standards applicable to calculating transfer capabilities in the Operating Horizon, which “ATC” values are utilized for the sale of transmission service. In Order 729 (Â¶ 289), FERC required NERC to modify FAC-012 and FAC-013 such that those standards would require and be the applicable standards for calculation of transfer capability values for the Planning Horizon and such that the criteria used for calculations would be “identical” between the planning and operating horizons. Hence, it is not clear if the intention of this standard and the PTCMD is to describe an entity’s methodology for calculation of “ATC” values for the Planning Horizon or, rather, if the intention of this standard and the PTCMD is to describe an entity’s methodology for calculation of FCITC values for the Planning Horizon. Additional, detailed comments are provided under question 3 (R1.1 & R1.1.4).
Response: The standard has been clarified to be applicable to the Near-Term Transmission Planning Horizon. The PTC and PTCMD definitions have been deleted based on industry comments and the concept of a transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The standard’s emphasis is on assessment of future reliability and		

Organization	Yes or No	Question 2 Comment
facilities that may be impacted by changes in transfers - not specific transfer capability values.		
Midwest ISO	No	The development of the PTCMD, as described in the standard, creates confusion as to whether the PTCMD is intended to describe: (1) the entity's methodology for continued calculation of ATC for the 2 to 5 year horizon as such values would be calculated in response to specific transmission service requests or (2) the entity's methodology for calculation of FCITC in the 2 to 5 year horizon. Clarity as to the applicability and scope for which the PTCMD is intended is critical for compliance with this standard as ATC and FCITC are calculated differently for different purposes. Currently, Reliability Coordinators calculate FCITC in the operating horizon in the seasonal pre-summer and pre-winter operating studies or seasonal assessments in accordance with the current, approved standards FAC-012-1 and FAC-013-1. The MOD standards were approved by the Federal Energy Regulatory Commission ("FERC") in Order 729 as the standards applicable to calculating transfer capabilities in the Operating Horizon, which ATC values are utilized for the sale of transmission service. In Order 729 (Â¶ 289), FERC required NERC to modify FAC-012 and FAC-013 such that those standards would require and be the applicable standards for calculation of transfer capability values for the Planning Horizon and such that the criteria used for calculations would be "identical" between the planning and operating horizons. Hence, it is not clear if the intention of this standard and the PTCMD is to describe an entity's methodology for calculation of ATC values for the Planning Horizon or, rather, if the intention of this standard and the PTCMD is to describe an entity's methodology for calculation of FCITC values for the Planning Horizon. Additional, detailed comments are provided under question 3 (R1.1 & R1.1.4) below.
Response: The standard has been clarified to be applicable to the Near-Term Transmission Planning Horizon. The PTC and PTCMD definitions have been deleted based on industry comments and the concept of a transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values.		
Kansas City Power & Light	No	The development of the PTCMD, as described in the standard, creates confusion as to whether the PTCMD is intended to describe: (1) the entity's methodology for continued calculation of ATC for the 2 to 5 year horizon as such values would be calculated in response to specific transmission service requests or (2) the entity's methodology for calculation of FCITC in the 2 to 5 year horizon. Clarity as to the applicability and scope for which the PTCMD is intended is critical for compliance with this standard as ATC and FCITC are calculated differently for different purposes. Currently, Reliability Coordinators calculate FCITC in the operating horizon in the seasonal pre-summer and pre-winter operating studies or seasonal assessments in accordance with the current, approved standards FAC-012-1 and FAC-013-1. The MOD standards were approved by the Federal Energy Regulatory Commission ("FERC") in Order 729 as the standards applicable to calculating transfer capabilities in the Operating Horizon, which ATC values are utilized for the sale of transmission service. In Order 729 (Â¶ 289), FERC required NERC to modify FAC-012 and FAC-013 such

Organization	Yes or No	Question 2 Comment
		that those standards would require and be the applicable standards for calculation of transfer capability values for the Planning Horizon and such that the criteria used for calculations would be "identical" between the planning and operating horizons. Hence, it is not clear if the intention of this standard and the PTCMD is to describe an entity's methodology for calculation of ATC values for the Planning Horizon or, rather, if the intention of this standard and the PTCMD is to describe an entity's methodology for calculation of FCITC values for the Planning Horizon. Additional, detailed comments are provided under question 3 (R1.1 & R1.1.4) below.
Response: The standard has been clarified to be applicable to the Near-Term Transmission Planning Horizon. The PTC and PTCMD definitions have been deleted based on industry comments and the concept of a transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values.		
Northeast Power Coordinating Council	No	Refer to the response to Question 1.
Response: See response to Q1		
ISO New England Inc.	No	See comment #1
Response: See response to Q1.		
Independent Electricity System Operator	No	For the same reason indicated under Q1, we disagree with the need to define PTCID.
Response: See response to Q1.		
Florida Municipal Power Agency	No	Mention should be made of the assumptions as well as the process / method
Response: The PTCMD definition has been deleted based on industry comments.		
FMPA	No	Mention should be made of the assumptions as well as the process / method.
Response: The PTCMD definition has been deleted based on industry comments.		

Organization	Yes or No	Question 2 Comment
Beaches Energy Services (of the City of Jacksonville Beach, FL)	No	Mention should be made of the assumptions as well as the process / method.
Response: The PTCMD definition has been deleted based on industry comments.		
California ISO	No	How is this definition and methodology different from the SOL methodology for the planning horizon in FAC-010-2.1? What is the difference between PTCs and SOLs in the planning horizon? Is FAC-013-2 duplicative with FAC-010-2.1 and FAC-014, and therefore potentially unnecessary?
Response: The PTCMD definition has been deleted based on industry comments and the concept of transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values nor defining SOLs.		
PNMR	No	See previous comment.
Response: See response to Q1.		
Xcel Energy	No	Xcel Energy believes that it is not necessary to create a new defined term, whether PTCID or PTCMD, for the following reasons: (1) We are unable to appreciate why the existing use of Transfer Capability Methodology within FAC-012-1 (which is not a defined term) becomes inadequate for continued usage - is there anything in the FERC Order 729 that requires defining TCMD? (2) We believe that continuing usage of Transfer Capability Methodology by stating the term within parenthesis at its first occurrence in R1 within the relevant standard will be wholly consistent with the existing paradigm - note that the term Facility Ratings Methodology is only used in FAC-008, and the term SOL Methodology is only used in FAC-010/011, and none of them are glossary terms.
Response: The PTCMD definition has been deleted based on industry comments and the concept of transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon.		
WAPA-RMR	Yes	The process outlined in the proposed FAC-013-2 is defined within the WECC at this time as the Path Rating Process. This proposed FAC seems duplicative to this existing practice in WECC.

Organization	Yes or No	Question 2 Comment
Response: Some existing practices may be duplicative of this standard. Therefore, compliance with the new standard should be more easily achieved.		
AECI	Yes	
Georgia Transmission Corporation	Yes	
Duke Energy	Yes	
East Kentucky Power Cooperative, Inc.	Yes	
Manitoba Hydro	Yes	
United Illuminating	Yes	
Orlando Utilities Commision	Yes	
South Carolina Electric and Gas	Yes	
Southern Company	Yes	
Tampa Electric Company	Yes	
FPL Transmission Planning	Yes	
Progress Energy Florida	Yes	
Tennessee Valley Authority	Yes	
SERC Planning Standards Subcommittee	Yes	
Bonneville Power Administration	Yes	

Organization	Yes or No	Question 2 Comment
WECC		Agree with the revised definition, but as indicated in the response to question 1, what is the need?
Response: The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers. The SDT believes there is a reliability related need for this assessment to be conducted.		
LG&E and KU Energy LLC		

3. The SDT has modified the Requirements to include data and modeling information as well as provide for additional clarity regarding the intent of the Requirement. Do you agree that the revised Requirements accomplish this goal?

Summary Consideration: Several of the negative commenters asked for further clarity as to the intent of the standard and the Planning Transfer methodology Document. The SDT explained that the standard had been clarified to be applicable to the Near-Term Transmission Planning Horizon and that the PTC and PTCMD definitions had been deleted based on industry comments. In addition, the concept of a transfer capability assessment in the Near-Term Planning Horizon had been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. Also, the standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers, not specific transfer capability values.

Some of the negative commenters felt there should be a new sub-requirement added that required a listing of long term firm point to point transmission service that would consume PTC. The SDT explained that the current Requirement R1 Part 1.3 required that the current and projected transmission uses be addressed and that the long term point to point transmission service data was available on transmission providers' OASIS.

A few of the negative comments indicated confusion as to the intent of Requirement R1 Part 1.3 and questioned why Requirement R1 Part 1.4 was in the standard. They also questioned whether the last bullet of Requirement R1 Part 1.1 was necessary. The SDT removed the last bullet in Requirement R1 Part 1.1 from the standard. The intent of Requirement R1 Part 1.3. (now Requirement R1 Part 1.2) was to ensure the methodology required the processes Planning Coordinators use to determine and assess transfer capabilities with respect to all applicable known SOLs. Requirement R1 Part 1.4. (now Requirement R1 Part 1.3) was included to implement a FERC directive.

Organization	Yes or No	Question 3 Comment
Northeast Power Coordinating Council	No	R1-part 1.1-last bullet - Referring to the following text: "Reliability margins applied to reflect uncertainty with BES conditions." The language requires that a reducing factor should be applied to calculated transfer capabilities to account for uncertainty in BES conditions. The document requires the user to modify, through a probabilistic approach, the base system representation with respect to the in-service status of BES elements. This consideration is currently not part either of the methodology employed for transfer capability calculations, nor is it acceptable to employ it going forward, given the fact that a transmission adequacy assessment such as this one is deterministic in nature. Moreover, transfer capability, from a planning perspective, is performed assuming all commercially operating system elements in service. On the other hand, the calculation of System Operating Limits is an assessment of specific system conditions projected for the short term horizon (e.g. seasonally). The probabilistic treatment of BES elements, with respect to their in-

Organization	Yes or No	Question 3 Comment
		service status, is currently already employed in other types of reliability analysis, such as LOLE (Loss of Load Expectation) assessments.Requirement 1.3 is unclear as to what the intent is. With respect to R1.4, what is the need or basis for this requirement? Requirement R3 is inconsistent with established and accepted regional practices and needs to make allowances for these.
Response: The referenced last bullet has been removed from the standard. The intent of Requirement R1 Part 1.3 (now Requirement R1 Part 1.2) is to ensure the methodology requires the processes Planning Coordinators use to determine and assess transfer capabilities respect all applicable known SOLs. Requirement R1 Part 1.4. (now Requirement R1 Part 1.3.) is include to address a FERC directive. The SDT is not clear how Requirement R.3. is, or could be, inconsistent with any regional practices.		
Independent Electricity System Operator	No	We concur with the list of elements to be addressed in R1.1, and with the inclusion of R1.2 and R1.5, but have the following comments on R1.3 and R1.4.R1.3 - For clarity we recommend appending " including IROLs."R1.4 should be removed. The appropriate assumptions are determined by the planning assessment personnel. The assumption can be more or less stringent than those applied in the operation horizon depending on the known and expected system conditions. Also, the criteria used in the two horizons can be different. For example, the TPL standards stipulate the contingency and performance requirements for planning assessment but the same set of comprehensive requirements do not currently exist for operation study or SOL/IROL calculations. Some in the industry have made it known that they would apply different contingency/performance criteria to operation assessment and in planning assessment. The industry's rejection to the SAR 2 years ago which proposed changes to FAC-010 and FAC-011 to achieve consistency in the planning and operation criteria provides this evidence.
Response: The SDT believes IROLs are included by definition and including again would be redundant. Requirement R1 Part 1.4. (now Requirement R1 Part 1.3.) is included to address a FERC directive. It has been modified to include the phrase "… consistent with the Planning Coordinator's planning practices."		
ISO New England Inc.	No	Requirement R3 is inconsistent with established and accepted regional practices and needs to make allowances for these. Requirement 1.3 is unclear as to what the intent is, with respect to R1.4, what is the need or basis for this requirement?
Response: The SDT is not clear how R.3 is or could be, inconsistent with any regional practices. The intent of Requirement R1 Part 1.3 (now Requirement R1 Part 1.2) is to ensure the methodology requires the processes Planning Coordinators use to determine and assess transfer capabilities respect all known SOL's. Requirement R1 Part 1.4. (now Requirement R1 Part 1.3.) is include to address a FERC directive. The SDT is not clear how Requirement R.3. is, or could be, inconsistent with any regional practices.		
FPL Transmission Planning	No	The Purpose of the standard states that Planning Transmission Capabilities are needed for reliable planning of the Bulk Electric System. The PTC forecasts need to be reliability based to be meaningful for planning by

Organization	Yes or No	Question 3 Comment
		determining adequate long term capability to ensure reliable operation in the future. Consistent with the stated purpose, Requirement R1.2 should be changed from “A list of all PTCs to be calculated” to “A list of PTCs to be calculated, which are needed for reliability planning coordination”
Response: The standard has been modified to allow for a methodology that results in a more efficient and flexible process of determining or assessing the impacts of transfers on facilities in the Near-Term Transmission Planning Horizon. The standard no longer references or requires calculation of PTCs.		
Florida Municipal Power Agency	No	A new sub-requirement should be added that requires listing of existing long term firm point to point transmission service that would consume PTC (assuming PTC is a “total” and not an “available” number).
Response: Requirement R1 Part 1.3 requires that the current and projected transmission uses be addressed. This data is available on transmission providers’ OASIS.		
FMPA	No	A new sub-requirement should be added that requires listing of existing long term firm point to point transmission service that would consume PTC (assuming PTC is a “total” and not an “available” number).
Response: Requirement R1 Part 1.3 requires that the current and projected transmission uses be addressed. This data is available on transmission providers’ OASIS.		
Beaches Energy Services (of the City of Jacksonville Beach, FL)	No	A new sub-requirement should be added that requires listing of existing long-term firm, point-to- point transmission service that would consume PTC (assuming PTC is a “total” and not an “available” number).
Response: Requirement R1 Part 1.3 requires that the current and projected transmission uses be addressed. This data is available on transmission providers’ OASIS.		
IRC Standards Review Committee	No	As discussed above, it is not clear if the intention of this standard and the PTCMD is to describe an entity’s methodology for calculation of ATC values for the Planning Horizon or, rather, if the intention of this standard and the PTCMD is to describe an entity’s methodology for calculation of FCITC values for the Planning Horizon. More specifically, Requirement R1 requires that, at a minimum, the PTCMD include “a description of the assumptions and criteria used in the calculation of Planning Transfer Capabilities (PTCs) to include at a minimum how each of the following are addressed, or an explanation for any of the following not used in the calculation of PTC...”. Included in these required elements, at Part 1.1, are “Reliability margins applied to reflect uncertainty with BES conditions” and, at R1.4, are “A statement that the assumptions and criteria used to calculate PTCs are as, or more, limiting than the assumptions and criteria used in the operating horizon”. The inclusion of these elements in the calculation of PTC strongly suggests that the intent of this standard and the PTCMD is to describe an entity’s methodology for calculation of ATC values for the Planning Horizon.

Organization	Yes or No	Question 3 Comment
		More specifically, the requirement to include 'Reliability Margins' in the PTC calculation or to provide a justification for not doing so described in R1.1 strongly suggests that the standard has been drafted with the calculation of ATC values as its primary intent. The concept of reliability margins (Capacity Benefit Margin and Transmission Reserve Margin) was specifically designed for the purposes of calculating ATC and selling transmission service in response to FERC's final rules in Orders 888 and 889. Reliability margins are designed to ensure that transmission service is not sold past the point of where the Bulk Electric System ("BES") will be secure and to ensure that the network transmission customers will have access to generation resources. As well, the requirement set forth in R1.1.4, which requires that 'A statement that the assumptions and criteria used to calculate PTCs are as, or more, limiting than the assumptions and criteria used in the operating horizon' be included in the PTCMD indicates that the assumptions and criteria utilized to calculated ATC values under the MOD standards and PTC values under the draft FAC-013-2 standard should be as similar as possible, which also strongly suggests that the standard has been drafted with the calculation of ATC values as its primary intent. Further, the intent of R1.1.4 is unclear and seems counterintuitive to current practices in that the assumptions in the planning horizon are, by virtue of the uncertainties associated with effects of time, less accurate than the operating horizon. The calculation of ATC values in the planning horizon and, in particular, years 4 and 5 years would have no practical value and would not improve the reliability of the BES. Further, FERC specifically acknowledged, in Order 729, that planning horizon transfer capabilities "may not be so accurate to support long-term scheduling of the transmission system but ... that such forecasts will be useful for long-term planning." Hence, if the intent of this standard and the PTCMD is to describe an entity's methodology for calculation of ATC values for the Planning Horizon, such is contrary to FERC's guidance in Order 729 and would add no value to the long-term reliability of the BES. Finally, whether the intent of this standard and the PTCMD is to: (1) describe an entity's methodology for calculation of ATC values for the Planning Horizon, which is strongly indicated by the content of the standard as described above, or (2) describe an entity's methodology for calculation of FCITC values for the Planning Horizon, the standard remains unclear as to its intent and how planning horizon transfer capabilities should be calculated.
Response: The standard has been clarified to be applicable to the Near-Term Transmission Planning Horizon. The PTC definition has been deleted based on industry comments and the concept of a transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values.		
MRO's NERC Standards Review Subcommittee	No	As discussed above, it is not clear if the intention of this standard and the PTCMD is to describe an entity's methodology for calculation of ATC values for the Planning Horizon or, rather, if the intention of this standard and the PTCMD is to describe an entity's methodology for calculation of FCITC values for the Planning

Organization	Yes or No	Question 3 Comment
		Horizon. More specifically, Requirement R1 requires that, at a minimum, the PTCMD include "a description of the assumptions and criteria used in the calculation of Planning Transfer Capabilities (PTCs) to include at a minimum how each of the following are addressed, or an explanation for any of the following not used in the calculation of PTC...". Included in these required elements, at Part 1.1, are "Reliability margins applied to reflect uncertainty with BES conditions" and, at R1.4, are "A statement that the assumptions and criteria used to calculate PTCs are as, or more, limiting than the assumptions and criteria used in the operating horizon". The inclusion of these elements in the calculation of PTC strongly suggests that the intent of this standard and the PTCMD is to describe an entity's methodology for calculation of ATC values for the Planning Horizon. More specifically, the requirement to include 'Reliability Margins' in the PTC calculation or to provide a justification for not doing so described in R1.1 strongly suggests that the standard has been drafted with the calculation of ATC values as its primary intent. The concept of reliability margins (Capacity Benefit Margin and Transmission Reserve Margin) was specifically designed for the purposes of calculating ATC and selling transmission service in response to FERC's final rules in Orders 888 and 889. Reliability margins are designed to ensure that transmission service is not sold past the point of where the Bulk Electric System ("BES") will be secure and to ensure that the network transmission customers will have access to generation resources. As well, the requirement set forth in R1.1.4, which requires that 'A statement that the assumptions and criteria used to calculate PTCs are as, or more, limiting than the assumptions and criteria used in the operating horizon' be included in the PTCMD indicates that the assumptions and criteria utilized to calculated ATC values under the MOD standards and PTC values under the draft FAC-013-2 standard should be as similar as possible, which also strongly suggests that the standard has been drafted with the calculation of ATC values as its primary intent. Further, the intent of R1.1.4 is unclear and seems counterintuitive to current practices in that the assumptions in the planning horizon are, by virtue of the uncertainties associated with effects of time, less accurate than the operating horizon.The calculation of ATC values in the planning horizon and, in particular, years 4 and 5 years would have no practical value and would not improve the reliability of the BES. Further, FERC specifically acknowledged, in Order 729, that planning horizon transfer capabilities "may not be so accurate to support long-term scheduling of the transmission system but ... that such forecasts will be useful for long-term planning." Hence, if the intent of this standard and the PTCMD is to describe an entity's methodology for calculation of ATC values for the Planning Horizon, such is contrary to FERC's guidance in Order 729 and would add no value to the long-term reliability of the BES. Finally, whether the intent of this standard and the PTCMD is to: (1) describe an entity's methodology for calculation of ATC values for the Planning Horizon, which is strongly indicated by the content of the standard as described above, or (2) describe an entity's methodology for calculation of FCITC values for the Planning Horizon, the standard remains unclear as to its intent and how planning horizon transfer capabilities should be calculated.

Response: The standard has been clarified to be applicable to the Near-Term Transmission Planning Horizon. The PTC definition has been deleted based on industry comments and the concept of a transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw

Organization	Yes or No	Question 3 Comment
distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values.		
ERCOT	No	As discussed above, it is not clear if the intention of this standard and the PTCMD is to describe an entity's methodology for calculation of ATC values for the Planning Horizon or, rather, if the intention of this standard and the PTCMD is to describe an entity's methodology for calculation of FCITC values for the Planning Horizon. More specifically, Requirement R1 requires that, at a minimum, the PTCMD include "a description of the assumptions and criteria used in the calculation of Planning Transfer Capabilities (PTCs) to include at a minimum how each of the following are addressed, or an explanation for any of the following not used in the calculation of PTC...". Included in these required elements, at Part 1.1, are "Reliability margins applied to reflect uncertainty with BES conditions" and, at R1.4, are "A statement that the assumptions and criteria used to calculate PTCs are as, or more, limiting than the assumptions and criteria used in the operating horizon". The inclusion of these elements in the calculation of PTC strongly suggests that the intent of this standard and the PTCMD is to describe an entity's methodology for calculation of ATC values for the Planning Horizon. More specifically, the requirement to include 'Reliability Margins' in the PTC calculation or to provide a justification for not doing so described in R1.1 strongly suggests that the standard has been drafted with the calculation of ATC values as its primary intent. The concept of reliability margins (Capacity Benefit Margin and Transmission Reserve Margin) was specifically designed for the purposes of calculating ATC and selling transmission service in response to FERC's final rules in Orders 888 and 889. Reliability margins are designed to ensure that transmission service is not sold past the point of where the Bulk Electric System ("BES") will be secure and to ensure that the network transmission customers will have access to generation resources. As well, the requirement set forth in R1.1.4, which requires that 'A statement that the assumptions and criteria used to calculate PTCs are as, or more, limiting than the assumptions and criteria used in the operating horizon' be included in the PTCMD indicates that the assumptions and criteria utilized to calculated ATC values under the MOD standards and PTC values under the draft FAC-013-2 standard should be as similar as possible, which also strongly suggests that the standard has been drafted with the calculation of ATC values as its primary intent. Further, the intent of R1.1.4 is unclear and seems counterintuitive to current practices in that the assumptions in the planning horizon are, by virtue of the uncertainties associated with effects of time, less accurate than the operating horizon.The calculation of ATC values in the planning horizon and, in particular, years 4 and 5 years would have no practical value and would not improve the reliability of the BES. Further, FERC specifically acknowledged, in Order 729, that planning horizon transfer capabilities "may not be so accurate to support long-term scheduling of the transmission system but ... that such forecasts will be useful for long-term planning." Hence, if the intent of this standard and the PTCMD is to describe an entity's methodology for calculation of ATC values for the Planning Horizon, such is contrary to FERC's guidance in Order 729 and would add no value to the long-term reliability of the BES. Finally, whether the intent of this standard and the PTCMD is to: (1) describe an entity's methodology for calculation of ATC values for the Planning Horizon, which is strongly indicated by the content of the standard as

Organization	Yes or No	Question 3 Comment
		described above, or (2) describe an entity's methodology for calculation of FCITC values for the Planning Horizon, the standard remains unclear as to its intent and how planning horizon transfer capabilities should be calculated.Again, in a Region that does not have a transmission service market, the concept of transfer capabilities is not applicable, leaving no benefit to developing a PTCMD.
Response: The standard has been clarified to be applicable to the Near-Term Transmission Planning Horizon. The PTC definition has been deleted based on industry comments and the concept of a transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values.		
American Transmission Company	No	As discussed in Question 2, it is not clear if the intention of this standard and the PTCMD is to describe an entity's methodology for calculation of "ATC" values for the Planning Horizon or, rather, if the intention of this standard and the PTCMD is to describe an entity's methodology for calculation of FCITC values for the Planning Horizon. More specifically, Requirement R1 requires that, at a minimum, the PTCMD include "a description of the assumptions and criteria used in the calculation of Planning Transfer Capabilities (PTCs) to include at a minimum how each of the following are addressed, or an explanation for any of the following not used in the calculation of PTC...". Included in these required elements, at Part 1.1, are "Reliability margins applied to reflect uncertainty with BES conditions" and, at R1.4, are "A statement that the assumptions and criteria used to calculate PTCs are as, or more, limiting than the assumptions and criteria used in the operating horizon". The inclusion of these elements in the calculation of PTC strongly suggests that the intent of this standard and the PTCMD is to describe an entity's methodology for calculation of "ATC" values for the Planning Horizon. More specifically, the requirement to include 'Reliability Margins' in the PTC calculation or to provide a justification for not doing so described in R1.1 strongly suggests that the standard has been drafted with the calculation of ATC values as its primary intent. The concept of reliability margins (Capacity Benefit Margin and Transmission Reserve Margin) was specifically designed for the purposes of calculating ATC and selling transmission service in response to FERC's final rules in Orders 888 and 889. Reliability margins are designed to ensure that transmission service is not sold past the point of where the Bulk Electric System ("BES") will be secure and to ensure that the network transmission customers will have access to generation resources. As well, the requirement set forth in R1.1.4, which requires that 'A statement that the assumptions and criteria used to calculate PTCs are as, or more, limiting than the assumptions and criteria used in the operating horizon' be included in the PTCMD indicates that the assumptions and criteria utilized to calculated "ATC" values under the MOD standards and PTC values under the draft FAC-013-2 standard should be as similar as possible, which also strongly suggests that the standard has been drafted with the calculation of "ATC" values as its primary intent. Further, the intent of R1.1.4 is unclear and seems counterintuitive to current practices in that the assumptions in the planning horizon are, by virtue of the uncertainties associated with effects of time, less accurate than the operating horizon.The calculation of "ATC" values in the planning horizon and, in particular, years 4 and 5 years would have no practical value and

Organization	Yes or No	Question 3 Comment
		would not improve the reliability of the BES. Further, FERC specifically acknowledged, in Order 729, that planning horizon transfer capabilities "may not be so accurate to support long-term scheduling of the transmission system but ... that such forecasts will be useful for long-term planning." Hence, if the intent of this standard and the PTCMD is to describe an entity's methodology for calculation of "ATC" values for the Planning Horizon, such is contrary to FERC's guidance in Order 729 and would add no value to the long-term reliability of the BES. Finally, whether the intent of this standard and the PTCMD is to: (1) describe an entity's methodology for calculation of "ATC" values for the Planning Horizon, which is strongly indicated by the content of the standard as described above, or (2) describe an entity's methodology for calculation of FCITC values for the Planning Horizon, the standard remains unclear as to its intent and how planning horizon transfer capabilities should be calculated.
Response: The standard has been clarified to be applicable to the Near-Term Transmission Planning Horizon. The PTC definition has been deleted based on industry comments and the concept of a transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values.		
Midwest ISO	No	As discussed above, it is not clear if the intention of this standard and the PTCMD is to describe an entity's methodology for calculation of ATC values for the Planning Horizon or, rather, if the intention of this standard and the PTCMD is to describe an entity's methodology for calculation of FCITC values for the Planning Horizon. More specifically, Requirement R1 requires that, at a minimum, the PTCMD include "a description of the assumptions and criteria used in the calculation of Planning Transfer Capabilities (PTCs) to include at a minimum how each of the following are addressed, or an explanation for any of the following not used in the calculation of PTC...". Included in these required elements, at Part 1.1, are "Reliability margins applied to reflect uncertainty with BES conditions" and, at R1.4, are "A statement that the assumptions and criteria used to calculate PTCs are as, or more, limiting than the assumptions and criteria used in the operating horizon". The inclusion of these elements in the calculation of PTC strongly suggests that the intent of this standard and the PTCMD is to describe an entity's methodology for calculation of ATC values for the Planning Horizon. More specifically, the requirement to include 'Reliability Margins' in the PTC calculation or to provide a justification for not doing so described in R1.1 strongly suggests that the standard has been drafted with the calculation of ATC values as its primary intent. The concept of reliability margins (Capacity Benefit Margin and Transmission Reserve Margin) was specifically designed for the purposes of calculating ATC and selling transmission service in response to FERC's final rules in Orders 888 and 889. Reliability margins are designed to ensure that transmission service is not sold past the point of where the Bulk Electric System ("BES") will be secure and to ensure that the network transmission customers will have access to generation resources. As well, the requirement set forth in R1.1.4, which requires that 'A statement that the assumptions and criteria used to calculate PTCs are as, or more, limiting than the assumptions and criteria used in the operating horizon' be included in the PTCMD indicates that the assumptions and criteria utilized to

Organization	Yes or No	Question 3 Comment
		calculated ATC values under the MOD standards and PTC values under the draft FAC-013-2 standard should be as similar as possible, which also strongly suggests that the standard has been drafted with the calculation of ATC values as its primary intent. Further, the intent of R1.1.4 is unclear and seems counterintuitive to current practices in that the assumptions in the planning horizon are, by virtue of the uncertainties associated with effects of time, less accurate than the operating horizon.The calculation of ATC values in the planning horizon and, in particular, years 4 and 5 years would have no practical value and would not improve the reliability of the BES. Further, FERC specifically acknowledged, in Order 729, that planning horizon transfer capabilities "may not be so accurate to support long-term scheduling of the transmission system but ... that such forecasts will be useful for long-term planning." Hence, if the intent of this standard and the PTCMD is to describe an entity's methodology for calculation of ATC values for the Planning Horizon, such is contrary to FERC's guidance in Order 729 and would add no value to the long-term reliability of the BES. Finally, whether the intent of this standard and the PTCMD is to: (1) describe an entity's methodology for calculation of ATC values for the Planning Horizon, which is strongly indicated by the content of the standard as described above, or (2) describe an entity's methodology for calculation of FCITC values for the Planning Horizon, the standard remains unclear as to its intent and how planning horizon transfer capabilities should be calculated.
Response: The standard has been clarified to be applicable to the Near-Term Transmission Planning Horizon. The PTC definition has been deleted based on industry comments and the concept of a transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values.		
Kansas City Power & Light	No	As discussed above, it is not clear if the intention of this standard and the PTCMD is to describe an entity's methodology for calculation of ATC values for the Planning Horizon or, rather, if the intention of this standard and the PTCMD is to describe an entity's methodology for calculation of FCITC values for the Planning Horizon. More specifically, Requirement R1 requires that, at a minimum, the PTCMD include "a description of the assumptions and criteria used in the calculation of Planning Transfer Capabilities (PTCs) to include at a minimum how each of the following are addressed, or an explanation for any of the following not used in the calculation of PTC...". Included in these required elements, at Part 1.1, are "Reliability margins applied to reflect uncertainty with BES conditions" and, at R1.4, are "A statement that the assumptions and criteria used to calculate PTCs are as, or more, limiting than the assumptions and criteria used in the operating horizon". The inclusion of these elements in the calculation of PTC strongly suggests that the intent of this standard and the PTCMD is to describe an entity's methodology for calculation of ATC values for the Planning Horizon. More specifically, the requirement to include 'Reliability Margins' in the PTC calculation or to provide a justification for not doing so described in R1.1 strongly suggests that the standard has been drafted with the calculation of ATC values as its primary intent. The concept of reliability margins (Capacity Benefit Margin and Transmission Reserve Margin) was specifically designed for the purposes of calculating ATC and selling

Organization	Yes or No	Question 3 Comment
		transmission service in response to FERC's final rules in Orders 888 and 889. Reliability margins are designed to ensure that transmission service is not sold past the point of where the Bulk Electric System ("BES") will be secure and to ensure that the network transmission customers will have access to generation resources. As well, the requirement set forth in R1.1.4, which requires that 'A statement that the assumptions and criteria used to calculate PTCs are as, or more, limiting than the assumptions and criteria used in the operating horizon' be included in the PTCMD indicates that the assumptions and criteria utilized to calculated ATC values under the MOD standards and PTC values under the draft FAC-013-2 standard should be as similar as possible, which also strongly suggests that the standard has been drafted with the calculation of ATC values as its primary intent. Further, the intent of R1.1.4 is unclear and seems counterintuitive to current practices in that the assumptions in the planning horizon are, by virtue of the uncertainties associated with effects of time, less accurate than the operating horizon.The calculation of ATC values in the planning horizon and, in particular, years 4 and 5 years would have no practical value and would not improve the reliability of the BES. Further, FERC specifically acknowledged, in Order 729, that planning horizon transfer capabilities "may not be so accurate to support long-term scheduling of the transmission system but ... that such forecasts will be useful for long-term planning." Hence, if the intent of this standard and the PTCMD is to describe an entity's methodology for calculation of ATC values for the Planning Horizon, such is contrary to FERC's guidance in Order 729 and would add no value to the long-term reliability of the BES. Finally, whether the intent of this standard and the PTCMD is to: (1) describe an entity's methodology for calculation of ATC values for the Planning Horizon, which is strongly indicated by the content of the standard as described above, or (2) describe an entity's methodology for calculation of FCITC values for the Planning Horizon, the standard remains unclear as to its intent and how planning horizon transfer capabilities should be calculated.
Response: The standard has been clarified to be applicable to the Near-Term Transmission Planning Horizon. The PTC definition has been deleted based on industry comments and the concept of a transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values.		
California ISO	No	The intention of the FAC-013-2 standard is not clear. Are PTCs different from SOLs for the planning horizon? It appears duplicative with other existing NERC standards.
Response: The concept of transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values nor defining SOL's. The SDT believes there is a reliability related need for this assessment to be conducted. The SDT does not believe the TPL standards adequately cover the need at this time.		

Organization	Yes or No	Question 3 Comment
PNMR	No	This should be written to clarify the differences used in determining transfer capability in the planning horizon from determining transfer capability in the operations [or Operations Planning] horizon.
Response: The concept of transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values.		
Progress Energy Florida	No	R1.1 is adequate in general, but the inclusion of "Parallel path impacts (loop flows)" is inappropriate and inconsistent with the types of analyses that would be used to calculate PTC as stipulated in the existing TPL Standards. We suggest that the loop flow language be deleted.Furthermore, the Purpose of the standard states that calculating Planning Transfer Capabilities is for the reliable planning of the BES. Since the Purpose in A3 states that the calculation of PTC is limited to use for reliable planning, R1.2 should clarify this issue. We suggest editing R1.2 to state "A list of PTCs to be calculated as needed for the reliable planning of the Bulk Electric System". Such a modification is necessary in order for the work performed for FAC-013-2 to be consistent with the stated purpose in A3. We furthermore assert that the use of the word "all" is confusing and could lead PCs to interpret the extent of a PTC list in various ways, which is why we excluded it from our above suggested modifications.
Response: The SDT changed "Parallel path impacts (loop flow)" to read "Parallel path (loop flow) adjustments" to clarify what was intended. Additionally, the standard has been modified to allow for a methodology that results in a more efficient and flexible process of determining or assessing transfer capabilities in the Near-Term Transmission Planning Horizon. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values.		
Tennessee Valley Authority	No	The intent of the standard still lacks clarity. The purpose statement reads: "To ensure that Planning Coordinators calculate Planning Transfer Capabilities using an established method such that those forecasts of Transfer Capabilities are available for the reliable planning of the Bulk Electric System (BES)." Resource Planners within a Planning Coordinator's area need an awareness of Planning Transfer Capability into their area of load responsibility in order to plan for sufficient resources inside the area. There is no requirement in the standard to communicate Transfer Capability to the Resource Planners within the Planning Coordinator's area. The proposed standard does not require any coordination between Planning Coordinators in performing these calculations. Planning Transfer Capability that is calculated outside of a jointly coordinated Planning Coordinator study process will likely produce forecasts of Planning Transfer Capability that are less reflective of planned system capabilities.Under R1.1.1, we believe that "monitored facilities" assumptions and criteria should also be addressed in the PTCMD.We believe that requirement R1.1.3 should be modified to reflect

Organization	Yes or No	Question 3 Comment
		that PTC calculations respect TPL criteria as a basis for PTC calculations, rather than SOLs.The intent of R1.1.4 is unclear, particularly since the standard excludes calculation of Transfer Capability in the operating horizon (inside 13 months).
Response: The SDT believes that Requirement R2, Part 2.2 in the revised standard provides the means for Resource Planners within the Planning Coordinator's area to provide input in to and receive data from a Planning Coordinator's processes as part of this standard. Monitored facilities criteria have been added to Requirement R1 Part 1.1. (now Requirement R1 Part 1.4.). Requirement R1 Part 1.4. (now Requirement R1 Part 1.3.) is included to address a FERC directive. It has been modified to include the phrase "… consistent with the Planning Coordinator's planning practices." Requirements R2, R3 and R5 to share methodologies, and associated assessment results and supporting data adequately addresses coordination between Planning Coordinators.		
Bonneville Power Administration	Yes	While BPA understands the intent that the revised R1.1 does not limit the Planning Coordinator's ability to use additional assumptions and criteria in the calculation of Planning Transfer Capabilities, Bonneville believes R1.1 is unclear as written. Bonneville requests R1.1 to be changed to:"A description of the assumptions and criteria used in the calculation of Planning Transfer Capability (PTC)s to include, but not limited to, how each of the following are addressed, or an explanation for any of the following not used in the calculation of PTC." For example, Bonneville wants to ensure that assumptions and criteria such as ambient temperature can be considered in calculating PTCs.
Response: The SDT has modified Requirement R1 Part 1.1. (now Requirement R1 Part 1.4.) to improve the clarity of the requirement. Overall, R1 and the standard have been modified to allow for a methodology that results in a more efficient and flexible process of determining or assessing the impact of transfers on facilities in the Near-Term Transmission Planning Horizon.		
Xcel Energy	Yes	Suggest re-sequencing the parts within R1 so that the existing part 1.1 follows the existing part 1.4 and is immediately before the existing part 1.5 since part 1.5 is related to the assumptions/criteria listed within part 1.1. This will also result in part 1.2 (list of Transfer Capabilities) to be stated at the very beginning.
Response: The SDT has modified and re-sequenced parts within R1.		
Georgia Transmission Corporation	Yes	
Duke Energy	Yes	
East Kentucky Power Cooperative, Inc.	Yes	

Organization	Yes or No	Question 3 Comment
Manitoba Hydro	Yes	
United Illuminating	Yes	
Orlando Utilities Commision	Yes	
South Carolina Electric and Gas	Yes	
WAPA-RMR	Yes	
Southern Company	Yes	
Tampa Electric Company	Yes	
SERC Planning Standards Subcommittee	Yes	
AECI	Yes	

4. The SDT has modified the VRFs to better align with the risk associated with the Requirements. Do you agree that the VRFs are now more consistent with regards to the risk associated with the Requirements?

Summary Consideration: The majority of the industry stakeholders agreed that the VRFs were now more consistent with the risk associated with the Requirements.

However, one stakeholder felt that the VRFs should be in a table attached to the standard. The SDT explained that the location of the VRF's for this standard were consistent with NERC's standards format.

Organization	Yes or No	Question 4 Comment
Northeast Power Coordinating Council	No	Suggest listing the VRFs in a table as an attachment to the document.
Response: The location of the VRF's for this standard is consistent with NERC's standards format.		
PNMR	No	There is a problem with the VSL for R1. As proposed there is overlap between the Lower and Moderate VSL for R1.
Response: The SDT agrees and has modified the VSL for R1 to eliminate the overlap.		
Bonneville Power Administration	Yes	BPA agrees that the VRFs for all the requirements in FAC-013-2 should be Lower.
Response: The SDT thanks you for your affirmative response and clarifying comment.		
IRC Standards Review Committee	Yes	We thank the drafting team for revising these VRFs to be Lower. While we disagree with the need for the standard, we understand that requirements must include a VRF and support the assignment of "Lower" for the VRFs.
Response: The SDT thanks you for your affirmative response and clarifying comment.		
MRO's NERC Standards Review Subcommittee	Yes	We thank the drafting team for revising these VRFs to be Lower. We understand that requirements must include a VRF and support the assignment of "Lower" for the VRFs.

Organization	Yes or No	Question 4 Comment
Response: The SDT thanks you for your affirmative response and clarifying comment.		
Tampa Electric Company	Yes	Agree all should be lower
Response: The SDT thanks you for your affirmative response and clarifying comment.		
Kansas City Power & Light	Yes	We thank the drafting team for revising these VRFs to be Lower. While we disagree with the need for the standard, we understand that requirements must include a VRF and support the assignment of "Lower" for the VRFs.
Response: The SDT thanks you for your affirmative response and clarifying comment.		
FPL Transmission Planning	Yes	Agree that all requirements of this standard as drafted should be Lower.
Response: The SDT thanks you for your affirmative response and clarifying comment.		
ERCOT	Yes	We thank the drafting team for revising these VRFs to be Lower. While we disagree with the need for the standard, we understand that requirements must include a VRF and support the assignment of "Lower" for the VRFs.
Response: The SDT thanks you for your affirmative response and clarifying comment.		
American Transmission Company	Yes	We thank the drafting team for revising these VRFs to be Lower. While we disagree with the need for the standard, we understand that requirements must include a VRF and support the assignment of "Lower" for the VRFs.
Response: The SDT thanks you for your affirmative response and clarifying comment.		
Midwest ISO	Yes	We thank the drafting team for revising these VRFs to be Lower. While we disagree with the need for the standard, we understand that requirements must include a VRF and support the assignment of "Lower" for the VRFs.
Response: The SDT thanks you for your affirmative response and clarifying comment.		

Organization	Yes or No	Question 4 Comment
California ISO	Yes	We appreciate that the drafting team revised the VRFs to be “Lower”. While we question the need for the FAC-013-2 standard and whether it is duplicative with other existing NERC standards, we understand that requirements must include VRFs and support the assignment of “Lower” for the VRFs.
Response: The SDT thanks you for your affirmative response and clarifying comment.		
AECI	Yes	
Independent Electricity System Operator	Yes	
Beaches Energy Services (of the City of Jacksonville Beach, FL)	Yes	
East Kentucky Power Cooperative, Inc.	Yes	
Manitoba Hydro	Yes	
United Illuminating	Yes	
Orlando Utilities Commision	Yes	
South Carolina Electric and Gas	Yes	
Florida Municipal Power Agency	Yes	
FMPA	Yes	
Southern Company	Yes	
Georgia Transmission Corporation	Yes	

Organization	Yes or No	Question 4 Comment
Duke Energy	Yes	
Progress Energy Florida	Yes	
Tennessee Valley Authority	Yes	
SERC Planning Standards Subcommittee	Yes	
WAPA-RMR		No comments on VRFs.

5. The SDT has modified the Measures to better align with the Requirements. Do you agree that the Measures are now more consistent with the Requirements?

Summary Consideration: Most of the negative commenters felt that Measures M3 and M4 were simply restatements of the Requirements. The SDT modified Measures M3 and M4 to remove any restatement of the Requirements.

A couple of the negative comments indicated that the Measures should be consistent with regional practices. The SDT does not feel that enough information was provided within the comment for the SDT to understand the concern but the SDT did modify Measures M3 and M4 to provide additional clarity based on other stakeholder comments. Measures need to be consistent with the requirements in the continent-wide standard since they need to be applicable across all Regions.

Organization	Yes or No	Question 5 Comment
Northeast Power Coordinating Council	No	Measures should be consistent with regional practices.
Response: Measures need to be consistent with the requirements in the continent-wide standard since they need to be applicable across all Regions. The SDT thanks you for your response but does not believe that they have enough information to understand your concern. However, the SDT did revise Measures M3 and M4 to provide additional clarity.		
ISO New England Inc.	No	Measures should be consistent with regional practices.
Response: Measures need to be consistent with the requirements in the continent-wide standard since they need to be applicable across all Regions. The SDT thanks you for your response but does not believe that they have enough information to understand your concern. However, the SDT did revise Measures M3 and M4 to provide additional clarity.		
Florida Municipal Power Agency	No	M3 and M4 are simply restatements of the requirements. FMPA suggests adding “such as (examples of evidence)” statements similar to those provided in M1, M2 and M5.
Response: The SDT has revised Measures M3 and M4 to provide examples of acceptable evidence as suggested. .		
FMPA	No	M3 and M4 are simply restatements of the requirements. FMPA suggests adding “such as (examples of evidence)” statements similar to those provided in M1, M2 and M5.

Organization	Yes or No	Question 5 Comment
Response: The SDT has revised Measures M3 and M4 to provide examples of acceptable evidence as suggested.		
Beaches Energy Services (of the City of Jacksonville Beach, FL)	No	M3 and M4 are simply restatements of the requirements. BES suggests adding “such as (examples of evidence)” statements similar to those provided in M1, M2 and M5.
Response: The SDT has revised Measures M3 and M4 to provide examples of acceptable evidence as suggested.		
Southern Company	No	
California ISO	Yes	
SERC Planning Standards Subcommittee	Yes	
Bonneville Power Administration	Yes	
IRC Standards Review Committee	Yes	
MRO's NERC Standards Review Subcommittee	Yes	
Tampa Electric Company	Yes	
FPL Transmission Planning	Yes	
Xcel Energy	Yes	
Progress Energy Florida	Yes	
Tennessee Valley Authority	Yes	
Kansas City Power & Light	Yes	

Organization	Yes or No	Question 5 Comment
Midwest ISO	Yes	
AECI	Yes	
Independent Electricity System Operator	Yes	
ERCOT	Yes	
Georgia Transmission Corporation	Yes	
Duke Energy	Yes	
East Kentucky Power Cooperative, Inc.	Yes	
Manitoba Hydro	Yes	
United Illuminating	Yes	
Orlando Utilities Commision	Yes	
South Carolina Electric and Gas	Yes	
WAPA-RMR	Yes	
American Transmission Company	Yes	

6. The SDT has modified the VSLs to better align with the severity of non-compliance associated with the Requirements. Do you agree that the VSLs are now more consistent with regards to the severity of non-compliance associated with the Requirements?

Summary Consideration: Several of the negative commenters indicated that the VSLs for Requirement R1 should be expanded to include more gradations. The VSL for Requirement R1 was extensively revised and modified to be consistent with the new Requirement R1 and industry stakeholder comments. The SDT believes the revised gradations are now appropriate for each sub-part.

A few of the negative comments indicated an overlap in the lower and moderate VSLs for Requirement R1. The SDT modified the VSLs to be consistent with the new Requirement R1 and industry stakeholder comments and eliminated the overlap. Some commenters suggested that there should be High and Severe VSLs for noncompliance with Parts 1.4 and these were added. The SDT assigned a Lower VSL for failure to address one or two of the items listed in Requirement R1 Part 1.4; Moderate VSL for failure to miss three; High for missing four; Severe for missing more than four. A couple of the negative comments indicated that the VSLs were inconsistent in their numbering scheme and the term "notified" should be replaced with "made available to" in the VSLs for Requirement R5. Requirement R1 was extensively revised and the VSLs were modified to be consistent with the new Requirement R1. The SDT revised the wording in the VSL for Requirement R5 as noted by stakeholders to use the same phrasing, "made . . . available to" as used in the associated requirement. The SDT chose the increments for Requirements R1, R2, R3 and R5 that vary depending on the content of the requirement – this supports NERC's VSL Guidelines.

Organization	Yes or No	Question 6 Comment
WECC	No	There appears to be a problem with the VSL for R1. As proposed there is overlap between the Lower and Moderate VSL for R1. The Lower VSL reads: The Planning Coordinator has a PTCMD but failed to address one or TWO of the items listed in Requirement R1, Part 1.1.The second part of the Moderate VSL reads:The Planning Coordinator has a PTCMD but failed to address TWO or more of the items listed in Requirement 1, Part 1.1If the PC has a PTCMD but failed to address TWO of the items listed in Requirement R1, Part 1.1, they would meet the language of both the Lower and the Moderate VSL. Suggest you change the second part of the Moderate VSL to readThe Planning Coordinator has a PTCMD but failed to address THREE or more of the items listed in Requirement 1, Part 1.1
Response: Requirement R1 has been extensively revised; the SDT has modified the VSLs to be consistent with the new Requirement R1 and your comments. The SDT has modified the Requirement R1 Lower and Moderate VSLs to "The Planning Coordinator has a Transfer Capability Methodology but failed to address one or two of the items listed in Requirement R1 Part 1.4"; "The Planning Coordinator has a Transfer Capability Methodology but failed to incorporate one of the Requirement R1 Parts 1.1, 1.2, 1.3, and 1.5 OR The Planning Coordinator has a Transfer Capability Methodology but failed to address three of the items listed in		

Organization	Yes or No	Question 6 Comment
Requirement R1 Part 1.4.”		
FPL Transmission Planning	No	The VSLs for R1 Lower and Moderate are inconsistent or contain an error. Recommend changing Moderate VSL (second part) to “The Planning Coordinator has a PTCMD but failed to address three or more of the items listed in Requirement R1, Part 1.1. The High and Severe VSLs for R1 should spell out the numerical 2 and 3 as “two” and “three” for consistency. The changes in severity levels for R2, R3, and R5 should be in multiples of 30 days, not in multiples of 10 days, which seems haphazardly chosen and severe for requirements that all have Lower VRFs. Similarly, R4 should be in multiples of 25% rather than 5%, particularly since there should not be a need to calculate very many PTCs because they should only be calculated for reliability enhancement reasons. Finally, the word “notified” in each VSL for R5 should be replaced with “made available to” in order to be consistent with the wording in R5.
Response: Requirement R1 has been extensively revised; the SDT has modified the VSLs to be consistent with the new Requirement R1 and your comments. The SDT has modified the Requirement R1 Lower and Moderate VSLs to “The Planning Coordinator has a Transfer Capability Methodology but failed to address one or two of the items listed in Requirement R1 Part 1.4”; “The Planning Coordinator has a Transfer Capability Methodology but failed to incorporate one of the Requirement R1 Parts 1.1, 1.2, 1.3, and 1.5 OR The Planning Coordinator has a Transfer Capability Methodology but failed to address three of the items listed in Requirement R1 Part 1.4.” The SDT chose increments for R2, R3 and R5 that vary depending on the content of the requirement. R4 in the initial draft of FAC-013-2 has been replaced; the new VSLs for R4 do not use multiples. The SDT has modified Requirement R5 VSL to address your concern and the word, ‘notified’ was replaced with ‘made. . . . available’.		
California ISO	No	A revision to the VSL for R1 is needed. As currently proposed, there is an overlap (with “two” of the items) appearing in both the Lower and Moderate VSL for R1. If an entity fails to meet “two” of the items listed in requirement R1, Part 1.1, the entity would meet the language currently contained in both the Lower and in the Moderate VSL. We recommend the SDT change the second part of the Moderate VSL to read: “The Planning Coordinator has a PTCMD but failed to address three or more of the items listed in Requirement R1, Part 1.1”
Response: Requirement R1 has been extensively revised; the SDT has modified the VSLs to be consistent with the new Requirement R1 and your comments. The SDT has modified the Requirement R1 Lower and Moderate VSLs to “The Planning Coordinator has a Transfer Capability Methodology but failed to address one or two of the items listed in Requirement R1 Part 1.4”; “The Planning Coordinator has a Transfer Capability Methodology but failed to incorporate one of the Requirement R1 Parts 1.1, 1.2, 1.3, and 1.5 OR The Planning Coordinator has a Transfer Capability Methodology but failed to address three of the items listed in Requirement R1 Part 1.4.”		

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 6 Comment</th></tr>
<tr><td>SERC Planning Standards Subcommittee</td><td>No</td><td>Revise the High VSL for R3 to: The Planning Coordinator provided a documented response to a documented technical comment as required in R3 after 70 calendar days, but not more than 80 calendar days after receipt of the comment.

Revise the Severe VSL for R3 to: The Planning Coordinator failed to provide a documented response to a documented technical comment as required in R3 within 80 calendar days after receipt of the comment.

Revise the High VSL for R5 to: The Planning Coordinator notified one or more of the parties specified in Requirement R5 of its PTCs after 70 calendar days, but not more than 80 calendar days after their verification and recalculation.

Revise the Severe VSL for R3 to: The Planning Coordinator failed to notify one or more of the parties specified in Requirement R5 of its PTCs within 80 calendar days after their verification and recalculation.

The Lower VSLs for R3 and R5 appear to violate the NERC VSL guideline that increments for time frames should be no more than 10 days.</td></tr>
<tr><td colspan="3">Response: The SDT agrees with the intent of your proposed modification for the High VSL for R3 and made a conforming change. The high VSL for Requirement R3 now reads “The Planning Coordinator provided a documented response to a documented concern with its Transfer Capability Methodology as required in Requirement R3 more than 75 calendar days, but not more than 90 calendar days.”

The severe VSL for Requirement R3 now reads “The Planning Coordinator failed to provide a documented response to a documented concern with its Transfer Capability Methodology as required in Requirement R3 by more than 90 calendar days. OR The Planning Coordinator failed to respond to a documented concern with its Transfer Capability Methodology.”

The High VSL and Severe VSL for Requirement R5 have been modified to “The Planning Coordinator made its documented Transfer assessment available to one or more of the recipients of its Transfer Capability Methodology more than 75 calendar days after completion of the assessment, but not more than 90 calendar days after completion of the assessment” and “The Planning Coordinator failed to make its documented Transfer Capability assessment available to one or more of the recipients of its Transfer Capability Methodology more than 90 calendar days after completion of the assessment OR The Planning Coordinator failed to make its documented Transfer Capability assessment available to any of the recipients of its Transfer Capability Methodology.”

The NERC VSL guideline allows for justifiable deviations from the default 10-day increments.</td></tr>
<tr><td>South Carolina Electric and Gas</td><td>No</td><td>Revise the High VSL for R3 to: "The Planning Coordinator provided a documented response to a documented technical comment as required in R3 after 70 calendar days, but not more than 80 calendar days after receipt of the comment."   Revise the Severe VSL for R3 to: "The Planning Coordinator failed to provide a documented response to a documented technical comment as required in R3 within 80 calendar days after receipt of the comment."   Revise the High VSL for R5 to: "The Planning Coordinator notified one or more of the parties specified in Requirement R5 of its PTCs after 70 calendar days, but not more than 80 calendar days after their verification and recalculation."   Revise the Severe VSL for R3 to: "The</td></tr>
</table>

Organization	Yes or No	Question 6 Comment
		Planning Coordinator failed to notify one or more of the parties specified in Requirement R5 of its PTCs within 80 calendar days after their verification and recalculation." The Lower VSLs for R3 and R5 appear to violate the NERC VSL guideline that increments for time frames should be no more than 10 days.
Response: The SDT agrees with the intent of your proposed modification for the High VSL for R3 and made a conforming change.. The high VSL for Requirement R3 now reads "The Planning Coordinator provided a documented response to a documented concern with its Transfer Capability Methodology as required in Requirement R3 more than 75 calendar days, but not more than 90 calendar days." The severe VSL for Requirement R3 now reads "The Planning Coordinator failed to provide a documented response to a documented concern with its Transfer Capability Methodology as required in Requirement R3 by more than 90 calendar days. OR The Planning Coordinator failed to respond to a documented concern with its Transfer Capability Methodology." The High VSL and Severe VSL for Requirement R5 have been modified to "The Planning Coordinator made its documented Transfer assessment available to one or more of the recipients of its Transfer Capability Methodology more than 75 calendar days after completion of the assessment, but not more than 90 calendar days after completion of the assessment" and "The Planning Coordinator failed to make its documented Transfer Capability assessment available to one or more of the recipients of its Transfer Capability Methodology more than 90 calendar days after completion of the assessment OR The Planning Coordinator failed to make its documented Transfer Capability assessment available to any of the recipients of its Transfer Capability Methodology." The NERC VSL guideline allows for justifiable deviations from the default 10-day increments.		
IRC Standards Review Committee	No	We believe the VSLs for R1 should be expanded to include more gradations. Failure to include one element from Parts 1.2 through 1.5 should be a Lower VSL. Failure to include two elements should be a Moderate VSL. Failure to include three elements should be a High VSL. Failure to include four elements should be a Severe VSL.
Response: Requirement R1 has been extensively revised; the SDT has modified the VSLs to be consistent with the new Requirement R1 and your comments. The SDT has modified the Requirement R1 Lower and Moderate VSLs to "The Planning Coordinator has a Transfer Capability Methodology but failed to address one or two of the items listed in Requirement R1 Part 1.4"; "The Planning Coordinator has a Transfer Capability Methodology but failed to incorporate one of the Requirement R1 Parts 1.1, 1.2, 1.3, and 1.5 OR The Planning Coordinator has a Transfer Capability Methodology but failed to address three of the items listed in Requirement R1 Part 1.4." A High VSL was assigned for failure to address four of the items listed in Requirement R1 Part 1.4 – and a Severe was assigned for failure to address more than four of the items listed in Requirement R1 Part 1.4. The SDT feels that the gradations are now appropriate for each sub-part.		
MRO's NERC Standards Review Subcommittee	No	We believe the VSLs for R1 should be expanded to include more gradations. Failure to include one element from Parts 1.2 through 1.5 should be a Lower VSL. Failure to include two elements should be a Moderate VSL. Failure to include three elements should be a High VSL. Failure to include four elements should be a Severe VSL.

Organization	Yes or No	Question 6 Comment
Response: Requirement R1 has been extensively revised; the SDT has modified the VSLs to be consistent with the new Requirement R1 and your comments. The SDT has modified the Requirement R1 Lower and Moderate VSLs to "The Planning Coordinator has a Transfer Capability Methodology but failed to address one or two of the items listed in Requirement R1 Part 1.4"; "The Planning Coordinator has a Transfer Capability Methodology but failed to incorporate one of the Requirement R1 Parts 1.1, 1.2, 1.3, and 1.5 OR The Planning Coordinator has a Transfer Capability Methodology but failed to address three of the items listed in Requirement R1 Part 1.4." A High VSL was assigned for failure to address four of the items listed in Requirement R1 Part 1.4 – and a Severe was assigned for failure to address more than four of the items listed in Requirement R1 Part 1.4. The SDT feels that the gradations are now appropriate for each sub-part.		
ERCOT	No	We believe the VSLs for R1 should be expanded to include more gradations. Failure to include one element from Parts 1.2 through 1.5 should be a Lower VSL. Failure to include two elements should be a Moderate VSL. Failure to include three elements should be a High VSL. Failure to include four elements should be a Severe VSL.
Response: Requirement R1 has been extensively revised; the SDT has modified the VSLs to be consistent with the new Requirement R1 and your comments. The SDT has modified the Requirement R1 Lower and Moderate VSLs to "The Planning Coordinator has a Transfer Capability Methodology but failed to address one or two of the items listed in Requirement R1 Part 1.4"; "The Planning Coordinator has a Transfer Capability Methodology but failed to incorporate one of the Requirement R1 Parts 1.1, 1.2, 1.3, and 1.5 OR The Planning Coordinator has a Transfer Capability Methodology but failed to address three of the items listed in Requirement R1 Part 1.4." A High VSL was assigned for failure to address four of the items listed in Requirement R1 Part 1.4 – and a Severe was assigned for failure to address more than four of the items listed in Requirement R1 Part 1.4. The SDT feels that the gradations are now appropriate for each sub-part.		
American Transmission Company	No	We believe the VSLs for R1 should be expanded to include more gradations. Failure to include one element from Parts 1.2 through 1.5 should be a Lower VSL. Failure to include two elements should be a Moderate VSL. Failure to include three elements should be a High VSL. Failure to include four elements should be a Severe VSL.
Response: Requirement R1 has been extensively revised; the SDT has modified the VSLs to be consistent with the new Requirement R1 and your comments. The SDT has modified the Requirement R1 Lower and Moderate VSLs to "The Planning Coordinator has a Transfer Capability Methodology but failed to address one or two of the items listed in Requirement R1 Part 1.4"; "The Planning Coordinator has a Transfer Capability Methodology but failed to incorporate one of the Requirement R1 Parts 1.1, 1.2, 1.3, and 1.5 OR The Planning Coordinator has a Transfer Capability Methodology but failed to address three of the items listed in Requirement R1 Part 1.4." A High VSL was assigned for failure to address four of the items listed in Requirement R1 Part 1.4 – and a Severe was assigned for failure to address more than four of the items listed in Requirement R1 Part 1.4. The SDT feels that the gradations are now appropriate for each sub-part.		
Midwest ISO	No	We believe the VSLs for R1 should be expanded to include more gradations. Failure to include one element from Parts 1.2 through 1.5 should be a Lower VSL. Failure to include two elements should be a Moderate

Organization	Yes or No	Question 6 Comment
		VSL. Failure to include three elements should be a High VSL. Failure to include four elements should be a Severe VSL.
Response: Requirement R1 has been extensively revised; the SDT has modified the VSLs to be consistent with the new Requirement R1 and your comments. The SDT has modified the Requirement R1 Lower and Moderate VSLs to "The Planning Coordinator has a Transfer Capability Methodology but failed to address one or two of the items listed in Requirement R1 Part 1.4"; "The Planning Coordinator has a Transfer Capability Methodology but failed to incorporate one of the Requirement R1 Parts 1.1, 1.2, 1.3, and 1.5 OR The Planning Coordinator has a Transfer Capability Methodology but failed to address three of the items listed in Requirement R1 Part 1.4." A High VSL was assigned for failure to address four of the items listed in Requirement R1 Part 1.4 – and a Severe was assigned for failure to address more than four of the items listed in Requirement R1 Part 1.4. The SDT feels that the gradations are now appropriate for each sub-part.		
Kansas City Power & Light	No	We believe the VSLs for R1 should be expanded to include more gradations. Failure to include one element from Parts 1.2 through 1.5 should be a Lower VSL. Failure to include two elements should be a Moderate VSL. Failure to include three elements should be a High VSL. Failure to include four elements should be a Severe VSL.
Response: Requirement R1 has been extensively revised; the SDT has modified the VSLs to be consistent with the new Requirement R1 and your comments. The SDT has modified the Requirement R1 Lower and Moderate VSLs to "The Planning Coordinator has a Transfer Capability Methodology but failed to address one or two of the items listed in Requirement R1 Part 1.4"; "The Planning Coordinator has a Transfer Capability Methodology but failed to incorporate one of the Requirement R1 Parts 1.1, 1.2, 1.3, and 1.5 OR The Planning Coordinator has a Transfer Capability Methodology but failed to address more three of the items listed in Requirement R1 Part 1.4." A High VSL was assigned for failure to address four of the items listed in Requirement R1 Part 1.4 – and a Severe was assigned for failure to address more than four of the items listed in Requirement R1 Part 1.4. The SDT feels that the gradations are now appropriate for each sub-part.		
Tampa Electric Company	No	Chnages in severity levels should be based on 30 days not 10 days
Response: The SDT is unaware of a guideline that would have severity levels based on 30 days. The SDT chose increments for each requirement with increments that vary depending on the content of the requirement.		
Progress Energy Florida	No	The VSLs have an inconsistent numbering convention. For example the R1 Lower VSL uses the phrase "one or two of the items" while several other use numerals, e.g. the R1 Moderate VSL uses the phrase "1 of the items". We suggest spelling out the amounts as words rather than using numerals. Furthermore, the R2, R3, and R5 VSLs seem to apply time limits inconsistently, e.g. the R3 High VSL has a limit of 70 days whereas the R5 High VSL time limit has a limit of 80 days. We recommend that the SDT reevaluate the reasoning behind all of the time limits and consider a more standardized approach. Additionally, the word "notified" in the R5 VSLs should be changed to "made available to", along with other rearrangement of wording. For

Organization	Yes or No	Question 6 Comment
		example, the R5 Lower VSL should read "The Planning Coordinator made its PTCs available to one or more of the parties specified in Requirement R5 more than 30 calendar days after their verification and recalculation, but not more than 60 calendar days after their verification and recalculation". This edit is needed in order for the R5 VSLs to be consistent with the wording in R5.
Response: Requirement R1 has been extensively revised; the SDT has modified the VSLs to be consistent with the new Requirement R1 and your comments. The SDT has modified the Requirement R1 Lower and Moderate VSLs to "The Planning Coordinator has a Transfer Capability Methodology but failed to address one or two of the items listed in Requirement R1 Part 1.4"; "The Planning Coordinator has a Transfer Capability Methodology but failed to incorporate one of the Requirement R1 Parts 1.1, 1.2, 1.3, and 1.5 OR The Planning Coordinator has a Transfer Capability Methodology but failed to address more than two of the items listed in Requirement R1 Part 1.4." The SDT chose increments for R2, R3 and R5 with increments that vary depending on the content of the requirement. The SDT has modified the VSL for Requirement R5 to address you concerns.		
Southern Company	No	
Bonneville Power Administration	Yes	The VSLs are now more consistent with the severity levels, however there is some overlap between the Lower and Moderate VSL for R1. Bonneville proposes the following changes to the VSLs for R1:Lower VSL:The Planning Coordinator has a PTCMD but failed to address one or two of the items listed in Requirement R1, Part 1.1.Moderate VSL:The Planning Coordinator has a PTCMD but failed to incorporate 1 of the items listed in Requirement R1, Parts 1.2 through 1.5 ORThe Planning Coordinator has a PTCMD but failed to address two three or more of the items listed in Requirement 1, Part 1.1.
Response: Requirement R1 has been extensively revised; the SDT has modified the VSLs to be consistent with the new Requirement R1 and your comments. The SDT has modified the Requirement R1 Lower and Moderate VSLs to "The Planning Coordinator has a Transfer Capability Methodology but failed to address one or two of the items listed in Requirement R1 Part 1.4"; "The Planning Coordinator has a Transfer Capability Methodology but failed to incorporate one of the Requirement R1 Parts 1.1, 1.2, 1.3, and 1.5 OR The Planning Coordinator has a Transfer Capability Methodology but failed to address three of the items listed in Requirement R1 Part 1.4." The SDT feels that the gradations are now appropriate for each sub-part.		
AECI	Yes	
Independent Electricity System Operator	Yes	
Beaches Energy Services (of the City of Jacksonville Beach, FL)	Yes	

Organization	Yes or No	Question 6 Comment
Georgia Transmission Corporation	Yes	
Duke Energy	Yes	
East Kentucky Power Cooperative, Inc.	Yes	
Manitoba Hydro	Yes	
United Illuminating	Yes	
Orlando Utilities Commision	Yes	
Florida Municipal Power Agency	Yes	
FMPA	Yes	
Northeast Power Coordinating Council	Yes	
WAPA-RMR		No comments on VSLs.

7. When reviewing the mapping document posted with the proposed FAC-013-2 standard, do you believe that the proposed standard (considering only the requirements assigned to the Planning Coordinator) will lead to an improvement in reliability when compared to the standards it proposes to replace?

Summary Consideration: Most of the negative commenters did not agree that the proposed standard provided any additional clarity or planning value. The SDT explained that they believed there was a reliability related need for this assessment to be conducted and that the standard's emphasis was on assessment of future reliability and facilities that may be impacted by changes in transfers. The SDT did not believe that the TPL standards adequately covered the need at this time.

Some of the negative comments indicate that the additional requirements included in the new FAC-013-2 standard when compared to the FAC-012-1 did not add much value in terms of increased reliability. The SDT explained that this draft standard merges the planning requirements in FAC-012-1 and FAC-013-1 and that the standard's emphasis was on assessment of future reliability and facilities that may be impacted by changes in transfers. The SDT believes that the TPL standards did not adequately cover the need at this time and that coordination of planning assessments is important to effective planning for future reliable system performance and meets a reliability related need in accordance with the results-based philosophy.

A few of the negative comments indicated that the current draft of the FAC-013-2 standard caused confusion regarding the difference between a PTC and an SOL in the planning horizon. The PTC definition was deleted based on industry comments and the concept of a transfer capability assessment in the Near-Term Planning Horizon was clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. In addition, the standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers, not specific transfer capability values nor defining SOLs.

A couple of the negative comments indicated that this standard neglected that modeling information and decisions that go into calculating accurate transfer capability, and choosing meaningful paths to calculate, require close coordination and discussions between the parties involved. The proposed standard does not preclude entities from working cooperatively to develop their Planning Transfer Capability Methodologies. This standard would increase transparency, and develop a level of coordination that may not exist in all NERC regions. In addition, the TPL standards do not adequately cover the need at this time. This standard requires a response to written comments from parties that have a reliability related need for the assessment results and coordination of planning assessments is important to effective planning for future reliable system performance and meets a reliability related need in accordance with the results-based philosophy. The NERC Reliability Standards apply to all NERC registered entities while Order 890 processes do not and in many areas, the requirements of this standard are in concert with existing practices and are already considered good utility practice and therefore, this new standard codified these practices.

Organization	Yes or No	Question 7 Comment
Northeast Power Coordinating Council	No	This standard provides no additional reliability or planning value to the TPL Standards.
Response: The standard's emphasis has been revised to focus on assessment of future reliability and facilities that may be impacted by changes in transfers. The SDT believes there is a reliability related need for this assessment to be conducted. The SDT does not believe the TPL standards adequately cover the need at this time.		
IRC Standards Review Committee	No	No, the proposed standard for calculating Transfer Capability in the planning horizon will not lead to an improvement in reliability. The Planning Transfer Capability idea should be retired. This standard, as drafted, will result in additional administrative burden for Planning Coordinators, but will have no corresponding reliability value or benefit for the BES. In addition, it is likely that the standard, as drafted, will result in significant confusion and misunderstanding regarding the calculation of PTC values.
Response: The standard's emphasis has been revised to focus on assessment of future reliability and facilities that may be impacted by changes in transfers. The SDT believes there is a reliability related need for this assessment to be conducted. The SDT has made significant clarifying changes to the draft requirements based on comments provided by the industry.		
ERCOT	No	No, the proposed standard for calculating Transfer Capability in the planning horizon will not lead to an improvement in reliability. The Planning Transfer Capability idea should be retired. This standard, as drafted, will result in additional administrative burden for Planning Coordinators, but will have no corresponding reliability value or benefit for the BES. In addition, it is likely that the standard, as drafted, will result in significant confusion and misunderstanding regarding the calculation of PTC values.
Response: The standard's emphasis has been revised to focus on assessment of future reliability and facilities that may be impacted by changes in transfers. The SDT believes there is a reliability related need for this assessment to be conducted. The SDT has made significant clarifying changes to the draft requirements based on comments provided by the industry.		
United Illuminating	No	Since it is replacing an existing requirement there will be no improvement to reliability. It adds some clarity to the process.
Response: This draft standard merges the planning requirements in FAC-012-1 and FAC-013-1. The standard's emphasis has been revised to focus on assessment of future reliability and facilities that may be impacted by changes in transfers. The SDT believes there is a reliability related need for this assessment to be conducted.		
Bonneville Power Administration	No	Bonneville requests the following requirement to be added as R1.3.1."R1.3.1 SOLs calculated in the Planning Horizon can be used as PTCs." In the previous comment period, Bonneville asked for clarity regarding how

Organization	Yes or No	Question 7 Comment
		calculating Planning Transfer Capabilities differ from calculating Total Transfer Capability and/or System Operating Limits. BPA understands that the SDT is trying to create a quantity that is not defined by TTCs or SOLs. However, the SDT responses did not adequately explain how a PTC is different; only that it would be calculated when no TTC or SOL is calculated. Also, it is unclear to Bonneville how the calculation of a PTC will enhance the Planning Coordinator's understanding of system behavior. The PTC term creates more confusion rather than avoiding confusion with TTC and SOL.As a result, it is unclear to BPA why this value (PTC) needs to be calculated and have an associated NERC standard. To better understand what the SDT is attempting to accomplish with FAC-013-2, Bonneville requests specific real-world examples of how calculating a PTC is different than calculating a System Operating Limit (SOL) or Total Transfer Capability (TTC) for the planning period beyond 13 months. Otherwise, it seems redundant with FAC-010 and FAC-014.Bonneville also requests clarity on the additional reliability need to calculate PTCs above and beyond the reliability need to calculate SOLs and TTCs in the planning period beyond 13 months.
Response: The PTC definition has been deleted based on industry comments and the concept of transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The standard's emphasis has been revised to focus on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values nor defining SOL's. Based on industry feedback Requi9rement R1 and the associated Parts have been modified to add clarity.		
MRO's NERC Standards Review Subcommittee	No	It is likely that the standard, as drafted, will result in significant confusion and misunderstanding regarding the calculation of PTC values.
Response: The SDT has made significant clarifying changes to the draft requirements based on comments provided by the industry.		
WAPA-RMR	No	This proposed FAC-013 process is already in-place within the WECC (Three-Phase Rating Process).
Response: In many areas, the requirements of this standard are in concert with existing practices and are already considered good utility practice. Therefore, the new standard codifies these practices.		
ISO New England Inc.	No	This standard provides no reliability value addition to the TPL Standards.
Response: The standard's emphasis has been revised to focus on assessment of future reliability and facilities that may be impacted by changes in transfers. The SDT believes there is a reliability related need for this assessment to be conducted. The SDT does not believe the TPL standards adequately cover the need at this time.		
American Transmission Company	No	No, the proposed standard for calculating Transfer Capability in the planning horizon will not lead to an improvement in reliability. The Planning Transfer Capability idea should be retired. This standard, as drafted, will result in additional administrative burden for Planning Coordinators, but will have no corresponding

Organization	Yes or No	Question 7 Comment
		reliability value or benefit for the BES. In addition, it is likely that the standard, as drafted, will result in significant confusion and misunderstanding regarding the calculation of PTC values.
Response: The standard's emphasis has been revised to focus on assessment of future reliability and facilities that may be impacted by changes in transfers. The SDT believes there is a reliability related need for this assessment to be conducted. The SDT does not believe the TPL standards adequately cover the need at this time.		
Midwest ISO	No	No, the proposed standard for calculating Transfer Capability in the planning horizon will not lead to an improvement in reliability. The Planning Transfer Capability idea should be retired. This standard, as drafted, will result in additional administrative burden for Planning Coordinators, but will have no corresponding reliability value or benefit for the BES. In addition, it is likely that the standard, as drafted, will result in significant confusion and misunderstanding regarding the calculation of PTC values.
Response: The standard's emphasis has been revised to focus on assessment of future reliability and facilities that may be impacted by changes in transfers. The SDT believes there is a reliability related need for this assessment to be conducted. The SDT does not believe the TPL standards adequately cover the need at this time.		
Kansas City Power & Light	No	No, the proposed standard for calculating Transfer Capability in the planning horizon will not lead to an improvement in reliability. The Planning Transfer Capability idea should be retired. This standard, as drafted, will result in additional administrative burden for Planning Coordinators, but will have no corresponding reliability value or benefit for the BES. In addition, it is likely that the standard, as drafted, will result in significant confusion and misunderstanding regarding the calculation of PTC values.
Response: This draft standard merges the planning requirements in FAC-012-1 and FAC-013-1. The standard's emphasis has been revised to focus on assessment of future reliability and facilities that may be impacted by changes in transfers. The SDT believes there is a reliability related need for this assessment to be conducted.		
AECI	No	The modeling information and decisions that go into calculating accurate transfer capability, and choosing meaningful paths to calculate, requires close coordination and discussions between the parties involved. The existing standards insure that this will happen by requiring involvement between planning coordinators, reliability coordinators, and their respective regional reliability organizations. Without that oversight, and the forums that have been developed within the regional reliability organizations, overall coordination will be more difficult to accomplish by the individual planning coordinators acting alone as implied by this proposed standard.
Response: The SDT believes that this standard will increase transparency, and develop a level of coordination that may not exist in all NERC regions. The		

Organization	Yes or No	Question 7 Comment
proposed standard does not preclude entities from working cooperatively to develop their Planning Transfer Capability Methodologies. The SDT does not believe the TPL standards adequately cover the need at this time. The standard requires response to written comments from parties that have a reliability related need for the assessment. Coordination of planning assessments is important to effective planning for future reliable system performance and meets a reliability related need in accordance with the results-based philosophy. The NERC Reliability Standards apply to all NERC registered entities while Order 890 processes do not. In many areas, the requirements of this standard are in concert with existing practices and are already considered good utility practice. Therefore, the new standard codifies these practices.		
Independent Electricity System Operator	No	We assess that the mapping would result in maintaining the same level of reliability, not necessarily an improvement in reliability.
Response: This draft standard merges the planning requirements in FAC-012-1 and FAC-013-1. The standard's emphasis has been revised to focus on assessment of future reliability and facilities that may be impacted by changes in transfers. The SDT believes there is a reliability related need for this assessment to be conducted.		
East Kentucky Power Cooperative, Inc.	No	The additional requirements included in the new FAC-013-2 standard when compared to the FAC-012-1 do not add much value in terms of increased reliability. These items require the Planning Coordinator to simply describe in more detail which PTCs have been calculated and how. This will have minimal impact on reliability.
Response: This draft standard merges the planning requirements in FAC-012-1 and FAC-013-1. The standard's emphasis has been revised to focus on assessment of future reliability and facilities that may be impacted by changes in transfers. The SDT believes there is a reliability related need for this assessment to be conducted. The SDT does not believe the TPL standards adequately cover the need at this time. The standard requires response to written comments from parties that have a reliability related need for the assessment. Coordination of planning assessments is important to effective planning for future reliable system performance and meets a reliability related need in accordance with the results-based philosophy.		
California ISO	No	The current draft of the FAC-013-2 standard has caused confusion. We request that the SDT clearly state the difference between a PTC and an SOL in the planning horizon. FAC-013-2 appears duplicative with other existing NERC standards (i.e., FAC-010-2.1 and FAC-014) and we question whether FAC-013-2 is necessary. How would the methodology differ for the calculation of PTCs compared to the calculation of SOLs in the planning horizon?
Response: The PTC definition has been deleted based on industry comments and the concept of transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values nor defining SOL's.		
Xcel Energy	No	Xcel Energy is unsure of the system reliability need and/or benefit of computing planning horizon transfer capability, as required under draft FAC-013-2 or the existing FAC-012/013 standards. The system reliability

Organization	Yes or No	Question 7 Comment
		need is especially questionable for Xcel Energy's footprint within WECC, since the inter-regional transfer capability is virtually the same as the Transfer Capability for a WECC Major Path, recognizing that the WECC Major Paths are essentially inter-regional interfaces or cut-planes. Consequently, the SOL computed for a WECC Major Path using the methodology in FAC-010-1 and/or FAC-011-1 is not significantly different than its TTC computed using the MOD-029-1 methodology, or its TC computed using the existing FAC-012-1 methodology. Therefore, the planning horizon TC computed in accordance with draft FAC-013-2 is not expected to result in any new reliability metric for most entities within WECC.
Response: The PTC definition has been deleted based on industry comments and the concept of transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values nor defining SOLs. The SDT agrees that In many areas, the requirements of this standard are in concert with existing practices and are already considered good utility practice. Therefore, the new standard codifies these practices.		
Tennessee Valley Authority	No	
Tampa Electric Company	Yes	How the PTC is calculated including what assumptions will be made are crucial to determining the value of this requirement to the reliability of the BES
Response: The SDT thanks you for your affirmative response and clarifying comment.		
FPL Transmission Planning	Yes	Yes, if the PTC are truly designed to provide future planning information regarding reliability based capability limitations on the BES, then this standard would have value for improving reliability. Otherwise it would have little or no real value.
Response: The SDT agrees with your comment. The standard's emphasis has been revised to focus on assessment of future reliability and facilities that may be impacted by changes in transfers. The SDT believes there is a reliability related need for this assessment to be conducted. The SDT does not believe the TPL standards adequately cover the need at this time.		
Progress Energy Florida	Yes	Yes, but only if PTC is made "available for the reliable planning of the Bulk Electric System (BES)" [Purpose, A3]. Otherwise PTC has no applicable purpose.
Response: The standard's emphasis has been revised to focus on assessment of future reliability and facilities that may be impacted by changes in transfers. The standard requires response to written comments from parties that have a reliability related need for the assessment. Coordination of planning assessments is important to effective planning for future reliable system performance and meets a reliability related need in accordance with the results-based philosophy.		

Organization	Yes or No	Question 7 Comment
Florida Municipal Power Agency	Yes	
Beaches Energy Services (of the City of Jacksonville Beach, FL)	Yes	
Orlando Utilities Commision	Yes	
South Carolina Electric and Gas	Yes	
Georgia Transmission Corporation	Yes	
Manitoba Hydro	Yes	
Duke Energy	Yes	
FMPA	Yes	
Southern Company	Yes	

8. Please provide any other comments (that you have not already provided in response to the questions above) that you have on the proposed standard.

Summary Consideration: The majority of the negative commentes indicated that the Planning Transfer Capability term should be retired due to the lack of benefits for BES reliability and could cause additional burdens and confusion for the Planning Coordinators. The standard's emphasis has been revised to focus on assessment of future reliability and facilities that may be impacted by changes in transfers. The SDT believes there is a reliability related need for this assessment to be conducted. The TPL standards do not adequately cover the need at this time.

The proposed standard includes a peerreview process, and requires a response to documented comments from parties that have a reliability related need for the PTC assessment. Coordination of planning assessments is important to effective planning for future reliable system performance and meets a reliability related need in accordance with the results-based philosophy.

Several of the negative comments questioned the need for calculating PTC for each year 2 through 5. The standard no longer requires assessments to be performed for each year 2-5; the SDT revised the standard to require assessment of one year in the Near-Term Transmission Planning Horizon. The calculation of PTC's is no longer a requirement but assessments are expected to be conducted annually.

A couple of the negative comments indicated that the standard was important for the planning of the electric system. The SDT explained that some existing practices may be duplicative of this standard because we believe it is good utility practice. Therefore, the new standard codifies these practices and compliance with the new standard should be more easily achieved.

Organization	Yes or No	Question 8 Comment
Tampa Electric Company		R4 should not require calculating PTC for each year 2-5, only selected years as needed.
Response: The standard no longer requires assessments to be performed for each year 2-5 and have revised the standard to require assessment of one year in the Near-Term Transmission Planning Horizon. Calculation of PTC's is no longer a requirement. Assessments must be conducted annually.		
FPL Transmission Planning		Requirement R4 is unclear about what is meant by "for years two through five" and may be excessive. The requirement should allow for the PTC calculation to be performed on representative year(s) (years two through five) of the near-term planning horizon to capture changes affecting PTC. The requirement can be reworded as follows: "R4. Each planning Coordinator shall verify and, if assumptions or criteria as described in the PTCMD have changed, recalculate its PTCs consistent with its PTCMD for beyond 13 months and

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 8 Comment</th></tr>
<tr><td></td><td></td><td>representative year(s) of the timeframe through year five (to capture system changes that affect PTC) at least once each calendar year, with no more than 15 months between verifications.”</td></tr>
<tr><td colspan="3">Response: The SDT agrees that assessments do not need to be performed for each year 2-5 and have revised the standard to require assessment of one year in the Near-Term Transmission Planning Horizon.</td></tr>
<tr><td>Orlando Utilities Commision</td><td></td><td>Excellent work on this standard! Several Questions relating to R4: Question 1: By years two through five, is it intended for there to be a rigid frame of reference for year two? As an example is it two years beyond the calendar year you are doing the study? Or is year two expected to line up with year two from your TPL studies? Or is it intended the Planning Coordinator will define the exact reference for years two through five? Question 2: On the day the standard is effective, it’s pretty clear a PTCMD should be in place. However are entities expected to have PTC’s in place, or are they expected to calculate a set that Calendar year, or some other time frame.</td></tr>
<tr><td colspan="3">Response: The standard no longer requires assessments to be performed for each year 2-5 and have revised the standard to require assessment of one year in the Near-Term Transmission Planning Horizon. Calculation of PTC’s is no longer a requirement. The Planning Coordinator is required to conduct an assessment annually.</td></tr>
<tr><td>AECI</td><td></td><td>Requirement 4 should be explained as to clarify exactly what years two through five are needed for the recalculation of PTCs if assumptions and/or criteria have changed. There are not always current regionally coordinated models available for each year two through five, which should be taken into consideration.</td></tr>
<tr><td colspan="3">Response: The standard no longer requires assessments to be performed for each year 2-5 and have revised the standard to require assessment of one year in the Near-Term Transmission Planning Horizon.</td></tr>
<tr><td>Progress Energy Florida</td><td></td><td>Requirement R4 uses the term “for years two through five”, which is unclear given the differences in how the numbering of years is administered by the various PCs. R4 should include language addressing this issue, perhaps using alternate language as follows: “Each Planning Coordinator shall verify and, if assumptions or criteria as described in Requirement 1 Part 1.1 have changed, recalculate its PTCs consistent with its PTCMD and its particular year-numbering convention for years two through five at least once each calendar year with no more than 15 months between verifications.” Note that the phrase “verify, and if” needs to be changed to “verify and, if” in order for the sentence to be grammatically correct.

Measure M2 needs the comma punctuation after “PTCMD” deleted in order for the sentence to be grammatically correct.

Finally, we would like to reiterate that FAC-013-2 is being developed as part of the process of planning the</td></tr>
</table>

Organization	Yes or No	Question 8 Comment
		BES reliably. While we have suggested that this clarification would be best applied in R1.2, our general point is that this has not been appropriately clarified anywhere in the sub-requirements, and such clarification is necessary somewhere within the Requirements in order for FAC-013-2 to match the intent in the Purpose (A3).
Response: The standard no longer requires assessments to be performed for each year 2-5 and have revised the standard to require assessment of one year in the Near-Term Transmission Planning Horizon. Requirement R4 and Measure M2 have been modified and the grammatical issues you identified no longer exist. The SDT agrees that the standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values. The standard has been modified accordingly.		
Northeast Power Coordinating Council		o Text box on top of page 3 - Please explain within the document (perhaps even via a footnote) the difference between "Available Transfer Capabilities" and "Available Flowgate Capabilities". o Is there a particular significance to the fact that the document uses the term Limit when referring to System Operating Limits, and the term Capability when referring to Planning Transfer Capabilities? If the terms are deemed equivalent, then only one should be used to avoid confusion. Otherwise, a differentiation should be offered within the document, along with reasons for employing such a distinction.
Response: The PTC term has been deleted based on industry comments and the concept of transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC.		
SERC Planning Standards Subcommittee		The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Planning Standards Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.
Response: The SDT thanks you for your clarifying comment.		
Bonneville Power Administration		Bonneville believes the SDT does not address FERC's intent for modifications to FAC-012 and FAC-013.The SAR, in the 'Brief Description' section the FERC 729 quote provides a link back to FERC Order 693 setting the foundation for what the FAC-012 and FAC-013 standards are to address. This quote links the MOD ATC standards' calculation of transfer capability to the intent of what FERC desired of the modifications to FAC-012 and FAC-013.In the 'Detailed Description' section, FERC Order 729 paragraph 279, the intent of the FAC-012 and FAC-013 modifications is to '...calculate transfer capabilities for use in determining available transfer capability be identical to those used in planning and operating the system'. Also, regarding the Planning Horizon, in paragraph 289 FERC clarifies and is in agreement with NERC that the Planning Horizon

Organization	Yes or No	Question 8 Comment
		is 1 to 5 years.
Response: The SDT believes the draft3 FAC-013-2 meets this directive. The SDT considered the statements in P782 regarding transfer capabilities for use in determining ATC must be identical to those used in planning and operating the system. Understanding that even though ATC is not required to be calculated for the Near-Term Transmission Planning Horizon, the team felt any differences in "assumptions and criteria" between normal planning studies (steady state, stability, short circuit) and transfer simulations are consistent and the only differences are those that are technically necessary for the type of stress the transfer simulations place on the bulk power system. These differences are similar to the differences in assumptions and criteria between steady state analysis and stability analysis. The actual directive from P782 regarding transfer capability analysis to be consistent with Order 890 has also been met. The transfer simulation analysis does not treat users of the transmission system differently.		
IRC Standards Review Committee		The Planning Transfer Capability idea should be retired since it does not have any benefits for BES reliability, but will cause additional burden and confusion for Planning Coordinators: o Transfer capabilities in the planning horizon are not useful for the reliable planning of the transmission system and/or any expansion plans. The current, approved TPL standards already provide system expansion requirements to assure reliable system performance with regard to firm transfer commitments, but not to limits that may exceed those firm commitments such as those that would be indicated in PTC calculations. Further, it must be noted that there are no TPL standards that require system expansion for maintenance of transfer capabilities above firm transfer commitments. As such, transfer capabilities in the planning horizon provide no additional information that can be used for system planning. o Transfer capabilities calculated 2 to 5 years ahead are not useful to give system operators advance warning or appropriate, applicable operating limits because operating horizon conditions will be significantly different than those projected during the planning horizon (2 to 5 years previously). While we disagree with the need for the standard as a whole, the following comments on the specific requirements are offered: o R3 should be removed from the standard as it is an administrative requirement that is unnecessary, contrary to the results-based standards effort and duplicative of existing statutory requirements. More specifically, R3 mandates a stakeholder process for the PTCMD and the calculation of PTC values generally, which process provides no reliability benefit, but provides a method for entities to dispute or request modification to the calculation of specific PTC values, which exceptions must then be documented in a revised PTCMD. The requirement to respond to all technical comments and/or revise PTCs and the PTCMD would be a significant administrative burden to the Planning Coordinators. Additionally, it should be noted that the NERC Board of Trustees approved the results-based standards initiative which includes a specific, stated goal to eliminate purely administrative requirements, which R3 is. Finally, FERC Order 890 already contains requirements for transmission planners to have stakeholder process. Accordingly, stakeholders already have a process through which they can address, with Planning Coordinators, issues with values and/or assumptions used in the planning horizon and/or system expansion plans. o Part 2.3 should be either be removed due to its subjective nature or criteria for requesting such data should

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		be added to clarify what entities can request such data, under what circumstances they can do so, and how disputes regarding such requests are to be resolved. More specifically, R3 contains no indication regarding the entity that makes the determination that a functional entity had a reliability-related need to the PTCs. Additionally, there are no dispute resolution provisions to govern disagreements between Planning Coordinators and entities requesting data under R3. Accordingly, the drafting team should either remove R3 from the standard or review the functional entities in the functional model and add the specific entities that should have access to the PTCs.
Response: The standard's emphasis has been revised to focus on assessment of future reliability and facilities that may be impacted by changes in transfers. The SDT believes there is a reliability related need for this assessment to be conducted. The SDT does not believe the TPL standards adequately cover the need at this time. The standard no longer requires assessments to be performed for each year 2-5 and have revised the standard to require assessment of one year in the Near-Term Transmission Planning Horizon. R3 has been revised and focuses solely on the methodology – not on any actual calculations. This "peer review" process has been adopted in several other standards. No stakeholder process is mandated, the standards only requires a response to documented comments from parties that have a reliability related need for the assessment. Coordination of planning assessments is important to effective planning for future reliable system performance and meets a reliability related need in accordance with the results-based philosophy. The NERC Reliability Standards apply to all NERC registered entities. Order 890 processes does not.		
MRO's NERC Standards Review Subcommittee		The Planning Transfer Capability idea should be retired since it does not have any benefits for BES reliability, but will cause additional burden and confusion for Planning Coordinators: o Transfer capabilities in the planning horizon are not useful for the reliable planning of the transmission system and/or any expansion plans. The current, approved TPL standards already provide system expansion requirements to assure reliable system performance with regard to firm transfer commitments, but not to limits that may exceed those firm commitments such as those that would be indicated in PTC calculations. Further, it must be noted that there are no TPL standards that require system expansion for maintenance of transfer capabilities above firm transfer commitments. As such, transfer capabilities in the planning horizon provide no additional information that can be used for system planning. o Transfer capabilities calculated 2 to 5 years ahead are not useful to give system operators advance warning or appropriate, applicable operating limits because operating horizon conditions will be significantly different than those projected during the planning horizon (2 to 5 years previously). While we disagree with the need for the standard as a whole, the following comments on the specific requirements are offered: o R3 should be removed from the standard as it is an administrative requirement that is unnecessary, contrary to the results-based standards effort and duplicative of existing statutory requirements. More specifically, R3 mandates a stakeholder process for the PTCMD and the calculation of PTC values generally, which process provides no reliability benefit, but provides a method for

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American Transmission		The Planning Transfer Capability idea should be retired since it does not have any benefits for BES reliability, but will cause additional burden and confusion for Planning Coordinators: o Transfer capabilities in the

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The standard no longer requires assessments to be performed for each year 2-5 and have revised the standard to require assessment of one year in the Near-Term Transmission Planning Horizon.

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Midwest ISO		The Planning Transfer Capability idea should be retired since it does not have any benefits for BES reliability, but will cause additional burden and confusion for Planning Coordinators: o Transfer capabilities in the planning horizon are not useful for the reliable planning of the transmission system and/or any expansion plans. The current, approved TPL standards already provide system expansion requirements to assure reliable system performance with regard to firm transfer commitments, but not to limits that may exceed those firm commitments such as those that would be indicated in PTC calculations. Further, it must be noted that there are no TPL standards that require system expansion for maintenance of transfer capabilities above firm transfer commitments. As such, transfer capabilities in the planning horizon provide no additional information that can be used for system planning. o Transfer capabilities calculated 2 to 5 years ahead are not useful to give system operators advance warning or appropriate, applicable operating limits because operating horizon conditions will be significantly different than those projected during the planning horizon (2 to 5 years previously). While we disagree with the need for the standard as a whole, the following comments on the specific requirements are offered: o R3 should be removed from the standard as it is an administrative requirement that is unnecessary, contrary to the results-based standards effort and duplicative of existing statutory requirements. More specifically, R3 mandates a stakeholder process for the PTCMD and the calculation of PTC values generally, which process provides no reliability benefit, but provides a method for entities to dispute or request modification to the calculation of specific PTC values, which exceptions must then be documented in a revised PTCMD. The requirement to respond to all technical comments and/or revise PTCs and the PTCMD would be a significant administrative burden to the Planning Coordinators. Additionally, it should be noted that the NERC Board of Trustees approved the results-based standards initiative which includes a specific, stated goal to eliminate purely administrative requirements, which R3 is. Finally, FERC Order 890 already contains requirements for transmission planners to have stakeholder process. Accordingly, stakeholders already have a process through which they can address, with Planning Coordinators, issues with values and/or assumptions used in the planning horizon and/or system expansion plans. o Part 2.3 should be either be removed due to its subjective nature or criteria for requesting such data should be added to clarify what entities can request such data, under what circumstances they can do so, and how disputes regarding such requests are to be resolved. More specifically, R3 contains no indication regarding the entity that makes the determination that a functional entity had a reliability-related need to the PTCs. Additionally, there are no dispute resolution provisions to govern disagreements between Planning Coordinators and entities requesting data under R3. Accordingly, the drafting team should either remove R3 from the standard or review the functional entities in the functional model and add the specific entities that

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Kansas City Power & Light		The Planning Transfer Capability idea should be retired since it does not have any benefits for BES reliability, but will cause additional burden and confusion for Planning Coordinators: o Transfer capabilities in the planning horizon are not useful for the reliable planning of the transmission system and/or any expansion plans. The current, approved TPL standards already provide system expansion requirements to assure reliable system performance with regard to firm transfer commitments, but not to limits that may exceed those firm commitments such as those that would be indicated in PTC calculations. Further, it must be noted that there are no TPL standards that require system expansion for maintenance of transfer capabilities above firm transfer commitments. As such, transfer capabilities in the planning horizon provide no additional information that can be used for system planning. o Transfer capabilities calculated 2 to 5 years ahead are not useful to give system operators advance warning or appropriate, applicable operating limits because operating horizon conditions will be significantly different than those projected during the planning horizon (2 to 5 years previously). While we disagree with the need for the standard as a whole, the following comments on the specific requirements are offered: o R3 should be removed from the standard as it is an administrative requirement that is unnecessary, contrary to the results-based standards effort and duplicative of existing statutory requirements. More specifically, R3 mandates a stakeholder process for the PTCMD and the calculation of PTC values generally, which process provides no reliability benefit, but provides a method for entities to dispute or request modification to the calculation of specific PTC values, which exceptions must then be documented in a revised PTCMD. The requirement to respond to all technical comments and/or revise PTCs and the PTCMD would be a significant administrative burden to the Planning Coordinators. Additionally, it should be noted that the NERC Board of Trustees approved the results-based standards initiative which includes a specific, stated goal to eliminate purely administrative requirements, which R3 is. Finally, FERC Order 890 already contains requirements for transmission planners to have stakeholder process. Accordingly, stakeholders already have a process through which they can address, with Planning Coordinators, issues with values and/or assumptions used in the planning horizon and/or system expansion

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Response: The standard's emphasis has been revised to focus on assessment of future reliability and facilities that may be impacted by changes in transfers. The SDT believes there is a reliability related need for this assessment to be conducted. The SDT does not believe the TPL standards adequately cover the need at this time. The standard no longer requires assessments to be performed for each year 2-5 and have revised the standard to require assessment of one year in the Near-Term Transmission Planning Horizon. R3 has been revised and focuses solely on the methodology – not on any actual calculations. This "peer review" process has been adopted in several other standards. No stakeholder process is mandated, the standard only requires a response to documented comments from parties that have a reliability related need for the assessment. Coordination of planning assessments is important to effective planning for future reliable system performance and meets a reliability related need in accordance with the results-based philosophy. The NERC Reliability Standards apply to all NERC registered entities. Order 890 processes does not.		
LG&E and KU Energy LLC		LG&E and KU Energy LLC support the comments submitted by the Midwest ISO.
Response: The standard's emphasis has been revised to focus on assessment of future reliability and facilities that may be impacted by changes in transfers. The SDT believes there is a reliability related need for this assessment to be conducted. The SDT does not believe the TPL standards adequately cover the need at this time. The standard no longer requires assessments to be performed for each year 2-5 and have revised the standard to require assessment of one year in the Near-Term Transmission Planning Horizon. R3 has been revised and focuses solely on the methodology – not on any actual calculations. This "peer review" process has been adopted in several other standards. No stakeholder process is mandated, the standard only requires a response to documented comments from parties that have a reliability related need for the assessment. Coordination of planning assessments is important to effective planning for future reliable system performance and meets a reliability related need in accordance with the results-based philosophy. The NERC Reliability Standards apply to all NERC registered entities. Order 890 processes does not.		

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Duke Energy		The second to last paragraph in the whitepaper does not illustrate the concept of "as or more limiting" clearly. A better example would be something along the lines of: For example, if N-1-1 contingencies are used for evaluation in the operating horizon, N-1 contingencies could not be used to calculate PTC, because this criterion would be less limiting than what is being used in the operating horizon.
Response: The example has been dropped from the whitepaper because revisions to the standard removed the "as or more limiting" concept.		
East Kentucky Power Cooperative, Inc.		Sub-requirement 1.4 (A statement that the assumptions and criteria used to calculate PTCs are as, or more, limiting than the assumptions and criteria used in the operating horizon) is of questionable merit. There may be valid reasons why assumptions and criteria used in the operating horizon may be more limiting than those used in the planning horizon. Each Planning Coordinator should decide what criteria and assumptions are used in the planning horizon vs. the operating horizon without a requirement that the planning horizon is always as, or more, limiting. PTCs are not likely to translate into the operating horizon in any event. This sub-requirement has no positive impact on reliability of the BES.
Response: The SDT agrees and has modified the standard to require that the assumptions and criteria used to perform the assessment are consistent with the Planning Coordinator's planning practices. The standard's emphasis has been revised to focus on assessment of future reliability and facilities that may be impacted by changes in transfers. The SDT believes there is a reliability related need for this assessment to be conducted.		
United Illuminating		R1.4 Technical Comment: UI recognizes the intent of R1.4 is to attempt to provide consistency in the calculation between the Planning and Operating Horizon. However there will be instances where the assumptions and criteria used to calculate PTCs can not be as, or more, limiting than the assumptions and criteria used in the operating horizon. This is because the assumptions applicable to the two different horizons must be different due to changes in topology, generation or rules, or just more accurate information. Also, it is difficult to interpret what is meant by more limiting. UI does not believe that reliability requires consistency in the two time horizons.R4 editorial comment: The placement of the commas is incorrect. Does the drafting team mean to "verify and recalculate" or to verify and only recalculate if assumptions changed? Also, it is unclear what is being verified by the PC; is it the PTCMD, or the PTC results? R5 editorial comment. Proposed R5 is The Planning Coordinator shall make its PTCs available no later than 30 calendar days (following the verification or recalculation of those PTCs) to those entities identified in Requirement R2. The information that is in the parenthesis is required to make the requirement sensible. Consider removing the parenthesis.Implementation Plan: First, Can the implementation plan provide clarity for when is the PC required to initially issue the PTCMD to its adjacent PC's? Second, If the effective date is October 1 (first day, first calendar quarter) is the PC required to complete the R4 annual review in that quarter? Can the implementation plan be modified to move R4 effective date to the calendar year following implementation of R1? Lastly, as written, the PC is only required to calculate PTC per R5 following the verification and

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		recalculation process required in R4 following a change to (not the establishment of) the PTCMD. Is the PC required to calculate PTC per the PTCMD prior to the annual verification? Can the implementation plan be specific?
Response: The SDT agrees that clarification of 1.4 was necessary and has modified the standard to require that the assumptions and criteria used to perform the assessment are consistent with the Planning Coordinator's planning practices. Requirements R4 and R5 have been modified and the grammatical issues no longer exist. The standard has been clarified to require annual assessments. The effective date will be based on when the standard is approved.		
WAPA-RMR		WECC has a process in-place known as the Three-Phase Rating Process that encompasses the Requirements laid out in this proposed FAC-013-2 re-write. FAC-013 will result in a duplicative effort with no resulting increase in realibility in the West. Perhaps the WECC process can be re-written to accomplish meeting the Requirements of the proposed FAC-013-2 under a WECC-driven effort.
Response: Some existing practices may be duplicative of this standard because we believe it is good utility practice. Therefore, compliance with the new standard should be more easily achieved.		
ISO New England Inc.		This standard is not important for planning the electric system.
Response: In many areas, the requirements of this standard are in concert with existing practices and are already considered good utility practice. Therefore, the new standard codifies these practices.		
Independent Electricity System Operator		As indicated under Q1, a review of the Comment Report suggests that the majority of the commenters disagree with the need to define the terms PTC and PTCID. We are disappointed that the SDT chose to ignore the majority comments.
Response: Definitions for PTC and PTCID are no longer required.		
Xcel Energy		Should the Purpose statement contain the phrase "forecasts of" even though it was deleted from the PTC definition? Recommend reverting back to the Purpose statement of the existing FAC-012-1 and adapt it for planning time-frame by deleting "and operation" plus "or methodologies." The resulting Purpose will be as follows: "To ensure that Transfer Capabilities used in the reliable planning of the BES are determined based on an established methodology."Requirement R4 requires recalculating TC for "years two through five" but it is unclear what should be considered as year one. Suggest adopting the definition of Near-Term Transmission Planning Horizon from the draft TPL-001-2 (Project 2006-2) and use it in lieu of year numbers.
Response: The word "forecasts" is not necessary in the purpose. The standard's emphasis has been revised to focus on assessment of future reliability and		

Organization	Yes or No	Question 8 Comment
facilities that may be impacted by changes in transfers - not specific transfer capability values. The standard no longer requires assessments to be performed for each year 2-5 and have revised the standard to require assessment of one year in the Near-Term Transmission Planning Horizon.		

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Ballot Results	
Ballot Name:	Project 2010-10 FAC-013-2 Planning Transfer Capability - Non-binding Poll for VRFs and VSLs_in
Poll Period:	10/20/2010 - 11/3/2010
Ballot Type:	Initial
Total # Opinions:	279
Total Ballot Pool:	322
Summary Results	87% of those who registered to participate provided an opinion; 55% of those who provided an opinion indicated support for the VRFs and VSLs that were proposed.

Individual Ballot Pool Results

Segment	Organization	Member	Opinion	Comments
1	Allegheny Power	Rodney Phillips	Affirmative	
1	Ameren Services	Kirit S. Shah	Negative	View
1	American Electric Power	Paul B. Johnson	Abstain	
1	American Transmission Company, LLC	Jason Shaver		
1	Arizona Public Service Co.	Robert D Smith	Abstain	
1	Associated Electric Cooperative, Inc.	John Bussman	Abstain	
1	Avista Corp.	Scott Kinney	Negative	View
1	BC Transmission Corporation	Gordon Rawlings	Abstain	
1	Beaches Energy Services	Joseph S. Stonecipher	Negative	View
1	Black Hills Corp	Eric Egge	Negative	View
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	

1	CenterPoint Energy	Paul Rocha	Abstain	
1	Central Maine Power Company	Brian Conroy	Abstain	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Abstain	
1	City of Vero Beach	Randall McCamish	Negative	
1	Clark Public Utilities	Jack Stamper	Abstain	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy		
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	John K Loftis	Abstain	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	E.ON U.S.	Larry Monday		
1	East Kentucky Power Coop.	George S. Carruba	Affirmative	
1	Edison Electric Institute	David Batz	Abstain	
1	Empire District Electric Co.	Ralph Frederick Meyer	Affirmative	
1	Entergy Corporation	George R. Bartlett	Affirmative	
1	FirstEnergy Energy Delivery	Robert Martinko	Affirmative	

1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	
1	Gainesville Regional Utilities	Luther E. Fair	Affirmative	
1	GDS Associates, Inc.	Claudiu Cadar	Abstain	
1	Georgia Transmission Corporation	Harold Taylor, II	Affirmative	
1	Great River Energy	Gordon Pietsch		
1	Hoosier Energy Rural Electric Cooperative, Inc.	Robert Solomon		
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Idaho Power Company	Ronald D. Schellberg	Negative	View
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JEA	Ted E Hobson	Negative	View
1	Kansas City Power & Light Co.	Michael Gammon	Negative	
1	Keys Energy Services	Stan T. Rzad	Negative	View
1	Lake Worth Utilities	Walt Gill	Negative	View
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lee County Electric Cooperative	John W Delucca	Abstain	
1	Lincoln Electric System	Doug Bantam	Abstain	
1	Long Island Power Authority	Robert Ganley	Abstain	

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1	Manitoba Hydro	Michelle Rheault	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Abstain	
1	National Grid	Saurabh Saksena		
1	Nebraska Public Power District	Richard L. Koch	Abstain	
1	Nevada Power Co.	James McMorran		
1	New York Power Authority	Arnold J. Schuff	Affirmative	
1	Northeast Utilities	David H. Boguslawski	Abstain	
1	Northern Indiana Public Service Co.	Kevin M Largura	Negative	
1	NorthWestern Energy	John Canavan	Negative	
1	Ohio Valley Electric Corp.	Robert Mattey	Negative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Abstain	
1	Omaha Public Power District	Douglas G Peterchuck	Abstain	
1	Orlando Utilities Commission	Brad Chase	Negative	View
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	Pacific Gas and Electric Company	Chifong L. Thomas	Abstain	
1	PacifiCorp	Colt Norrish	Affirmative	

1	PECO Energy	Ronald Schloendorn	Affirmative	
1	Platte River Power Authority	John C. Collins	Negative	View
1	Portland General Electric Co.	Frank F. Afranji	Affirmative	View
1	Potomac Electric Power Co.	Richard J Kafka	Affirmative	
1	PowerSouth Energy Cooperative	Larry D. Avery	Negative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Progress Energy Carolinas	Sammy Roberts	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Negative	View
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Public Utility District No. 1 of Chelan County	Chad Bowman		
1	Puget Sound Energy, Inc.	Catherine Koch	Negative	View
1	Rochester Gas and Electric Corp.	John C Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Negative	View
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Linda Brown	Affirmative	
1	Santee Cooper	Terry L. Blackwell	Negative	
1	SCE&G	Henry Delk, Jr.	Affirmative	

1	Seattle City Light	Pawel Krupa	Negative	View
1	South Texas Electric Cooperative	Richard McLeon	Abstain	
1	Southern California Edison Co.	Dana Cabbell	Negative	
1	Southern Company Services, Inc.	Horace Stephen Williamson	Abstain	
1	Southern Illinois Power Coop.	William G. Hutchison	Negative	
1	Southwest Transmission Cooperative, Inc.	James L. Jones	Affirmative	
1	Southwestern Power Administration	Gary W Cox	Abstain	
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tampa Electric Co.	Beth Young	Negative	View
1	Tennessee Valley Authority	Larry Akens	Abstain	
1	Tri-State G & T Association, Inc.	Keith V. Carman	Negative	View
1	Tucson Electric Power Co.	John Tolo	Negative	View
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Abstain	
1	Western Area Power Administration	Brandy A Dunn	Negative	
1	Xcel Energy, Inc.	Gregory L Pieper	Abstain	
2	Alberta Electric System Operator	Mark B Thompson	Abstain	

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2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Gregory Van Pelt	Negative	View
2	Electric Reliability Council of Texas, Inc.	Chuck B Manning	Negative	View
2	Independent Electricity System Operator	Kim Warren	Negative	View
2	ISO New England, Inc.	Kathleen Goodman		
2	Midwest ISO, Inc.	Jason L Marshall	Negative	View
2	New Brunswick System Operator	Alden Briggs	Affirmative	
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
2	Southwest Power Pool	Charles H Yeung	Abstain	
3	Alabama Power Company	Richard J. Mandes	Abstain	
3	Allegheny Power	Bob Reeping	Affirmative	
3	Ameren Services	Mark Peters	Negative	
3	American Electric Power	Raj Rana	Abstain	
3	APS	Steven Norris	Negative	View
3	Atlantic City Electric Company	James V. Petrella	Affirmative	
3	Avista Corp.	Robert Lafferty	Negative	

3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Blue Ridge Power Agency	Duane S. Dahlquist	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse	Negative	
3	City of Clewiston	Lynne Mila		
3	City of Farmington	Linda R. Jacobson	Abstain	
3	City of Green Cove Springs	Gregg R Griffin	Negative	View
3	City of Leesburg	Phil Janik	Negative	
3	Cleco Corporation	Michelle A Corley	Negative	
3	ComEd	Bruce Krawczyk	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy	David A. Lapinski	Abstain	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Edwin Les Barrow		
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources Services	Michael F Gildea	Abstain	

3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	
3	East Kentucky Power Coop.	Sally Witt	Affirmative	
3	Entergy	Joel T Plessinger		
3	FirstEnergy Solutions	Kevin Querry	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Negative	
3	Florida Power & Light Co.	W. R. Schoneck	Negative	View
3	Florida Power Corporation	Lee Schuster		
3	Gainesville Regional Utilities	Kenneth Simmons	Negative	
3	Georgia Power Company	Anthony L Wilson	Abstain	
3	Georgia System Operations Corporation	R Scott S. Barfield-McGinnis	Affirmative	
3	Great River Energy	Sam Kokkinen		
3	Gulf Power Company	Gwen S Frazier	Abstain	
3	Hydro One Networks, Inc.	David L Kiguel	Affirmative	
3	JEA	Garry Baker	Negative	
3	Kansas City Power & Light Co.	Charles Locke	Negative	
3	Kissimmee Utility Authority	Gregory David Woessner	Affirmative	
3	Lakeland Electric	Mace Hunter	Abstain	

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3	Lincoln Electric System	Bruce Merrill		
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	Manitoba Hydro	Greg C Parent	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Abstain	
3	Mississippi Power	Don Horsley	Abstain	
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Affirmative	
3	Muscatine Power & Water	John S Bos	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	Marilyn Brown	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Abstain	
3	Northern Indiana Public Service Co.	William SeDoris	Negative	
3	Ocala Electric Utility	David T. Anderson	Negative	
3	Orlando Utilities Commission	Ballard Keith Mutters	Abstain	
3	PacifiCorp	John Apperson	Affirmative	
3	PECO Energy an Exelon Co.	Vincent J. Catania	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz	Negative	View

3	Potomac Electric Power Co.	Robert Reuter	Affirmative	
3	Progress Energy Carolinas	Sam Waters	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Public Utility District No. 2 of Grant County	Greg Lange	Negative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Negative	View
3	Salt River Project	John T. Underhill	Affirmative	
3	San Diego Gas & Electric	Scott Peterson		
3	Santee Cooper	Zack Dusenbury	Negative	
3	Seattle City Light	Dana Wheelock	Negative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	
3	South Carolina Electric & Gas Co.	Hubert C. Young	Affirmative	
3	Southern California Edison Co.	David Schiada	Negative	View
3	Tacoma Public Utilities	Travis Metcalfe	Abstain	
3	Tampa Electric Co.	Ronald L Donahey	Affirmative	
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Negative	View
3	Wisconsin Electric Power Marketing	James R. Keller	Abstain	

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3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	American Municipal Power - Ohio	Kevin Koloini	Abstain	
4	City of Clewiston	Kevin McCarthy		
4	City of New Smyrna Beach Utilities Commission	Timothy Beyrle		
4	Consumers Energy	David Frank Ronk	Abstain	
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	Detroit Edison Company	Daniel Herring		
4	Florida Municipal Power Agency	Frank Gaffney	Negative	View
4	Fort Pierce Utilities Authority	Thomas W. Richards		
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Abstain	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Negative	View
4	Seattle City Light	Hao Li	Negative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	

4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Abstain	
4	Wisconsin Energy Corp.	Anthony Jankowski	Abstain	
5	AEP Service Corp.	Brock Ondayko	Abstain	
5	Amerenue	Sam Dwyer	Negative	
5	APS	Mel Jensen		
5	Avista Corp.	Edward F. Groce	Negative	View
5	BC Hydro and Power Authority	Clement Ma		
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	View
5	Chelan County Public Utility District #1	John Yale		
5	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Max Emrick	Abstain	
5	Cleco Power	Stephanie Huffman	Negative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy	James B Lewis	Affirmative	
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	CPS Energy	Robert B Stevens		

5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	East Kentucky Power Coop.	Stephen Ricker	Affirmative	
5	Energy Northwest - Columbia Generating Station	Doug Ramey	Abstain	
5	Entergy Corporation	Stanley M Jaskot	Affirmative	
5	Exelon Nuclear	Michael Korchynsky	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Negative	View
5	Great River Energy	Cynthia E Sulzer		
5	Kansas City Power & Light Co.	Scott Heidtbrink		
5	Kissimmee Utility Authority	Mike Blough	Abstain	
5	Lakeland Electric	Thomas J Trickey		
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Louisville Gas and Electric Co.	Charlie Martin	Negative	View
5	Manitoba Hydro	S N Fernando	Affirmative	
5	MEAG Power	Steven Grego	Affirmative	

5	MidAmerican Energy Co.	Christopher Schneider	Negative	View
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Gerald Mannarino	Abstain	
5	Northern Indiana Public Service Co.	Michael K Wilkerson	Affirmative	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard Kinas	Abstain	
5	Pacific Gas and Electric Company	Richard J. Padilla		
5	PacifiCorp	Sandra L. Shaffer	Abstain	
5	Portland General Electric Co.	Gary L Tingley		
5	PowerSouth Energy Cooperative	Tim Hattaway	Abstain	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	
5	PSEG Power LLC	Jerzy A Slusarz		
5	RRI Energy	Thomas J. Bradish	Negative	View
5	Sacramento Municipal Utility District	Bethany Wright	Negative	View
5	Salt River Project	Glen Reeves	Affirmative	
5	Santee Cooper	Lewis P Pierce	Negative	

5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	
5	South Carolina Electric & Gas Co.	Richard Jones	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Affirmative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	George T. Ballew	Abstain	
5	Tri-State G & T Association, Inc.	Barry Ingold	Negative	
5	U.S. Army Corps of Engineers Northwestern Division	Karl Bryan	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer P.E.	Abstain	
5	Wisconsin Electric Power Co.	Linda Horn	Abstain	
5	Wisconsin Public Service Corp.	Leonard Rentmeester		
5	Xcel Energy, Inc.	Liam Noailles	Negative	View
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Negative	View
6	Arizona Public Service Co.	Justin Thompson	Abstain	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Negative	

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6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	
6	Constellation Energy Commodities Group	Brenda Powell	Abstain	
6	Dominion Resources, Inc.	Louis S Slade	Abstain	
6	Duke Energy Carolina	Walter Yeager	Affirmative	
6	Entergy Services, Inc.	Terri F Benoit	Affirmative	
6	Exelon Power Team	Pulin Shah	Affirmative	
6	FirstEnergy Solutions	Mark S Travaglianti	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	View
6	Florida Municipal Power Pool	Thomas E Washburn	Negative	View
6	Florida Power & Light Co.	Silvia P Mitchell		
6	Great River Energy	Donna Stephenson		
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	
6	Lakeland Electric	Paul Shipps	Negative	
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Louisville Gas and Electric Co.	Daryn Barker		
6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	MidAmerican Energy Co.	Dennis Kimm	Abstain	

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6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	
6	NRG Energy, Inc.	Alan R. Johnson	Abstain	
6	Omaha Public Power District	David Ried	Abstain	
6	PacifiCorp	Scott L Smith	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Negative	View
6	Portland General Electric Co.	John Jamieson		
6	PPL EnergyPlus LLC	Mark A Heimbach	Affirmative	
6	Progress Energy	John T Sturgeon	Affirmative	
6	PSEG Energy Resources & Trade LLC	James D. Hebson	Abstain	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	RRI Energy	Trent Carlson	Negative	View
6	Salt River Project	Mike Hummel	Affirmative	
6	Santee Cooper	Suzanne Ritter	Negative	
6	Seattle City Light	Dennis Sismaet	Negative	View
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	
6	Tacoma Public Utilities	Michael C Hill	Abstain	
6	Tampa Electric Co.	Joann Wehle	Affirmative	

6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Western Area Power Administration - UGP Marketing	John Stonebarger		
6	Xcel Energy, Inc.	David F. Lemmons		
8		James A Maenner	Abstain	
8		Roger C Zaklukiewicz	Affirmative	
8		Edward C Stein	Abstain	
8	JDRJC Associates	Jim D. Cyrulewski	Negative	
8	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	California Energy Commission	William Mitchell Chamberlain		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Affirmative	
9	North Carolina Utilities Commission	Kimberly J. Jones		
9	Oregon Public Utility Commission	Jerome Murray	Abstain	
9	Utah Public Service Commission	Ric Campbell	Affirmative	
10	Florida Reliability Coordinating Council	Linda Campbell	Abstain	
10	Midwest Reliability Organization	James D Burley	Abstain	

10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council, Inc.	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Negative	View
10	SERC Reliability Corporation	Carter B Edge	Abstain	
10	Southwest Power Pool Regional Entity	Stacy Dochoda	Affirmative	
10	Texas Reliability Entity	Larry D Grimm	Negative	View
10	Western Electricity Coordinating Council	Louise McCarren	Negative	View

Ballot Results	
Ballot Name:	Project 2010-10 FAC-013-2 Planning Transfer Capability_in
Ballot Period:	10/20/2010 - 11/3/2010
Ballot Type:	Initial
Total # Votes:	286
Total Ballot Pool:	323
Quorum:	**88.54 % The Quorum has been reached**
Weighted Segment Vote:	39.85 %
Ballot Results:	**The standard will proceed to recirculation ballot.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative		Negative		Abstain	No Vote
			# Votes	Fraction	# Votes	Fraction	# Votes	
1 - Segment 1.	95	1	26	0.388	41	0.612	19	9
2 - Segment 2.	11	1	2	0.2	8	0.8	1	0
3 - Segment 3.	76	1	25	0.455	30	0.545	11	10
4 - Segment 4.	19	1	5	0.455	6	0.545	4	4
5 - Segment 5.	60	1	20	0.476	22	0.524	9	9
6 - Segment 6.	42	1	11	0.355	20	0.645	8	3
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	6	0.5	2	0.2	3	0.3	1	0
9 - Segment 9.	5	0.3	1	0.1	2	0.2	0	2
10 - Segment 10.	9	0.8	4	0.4	4	0.4	1	0
Totals	**323**	**7.6**	**96**	**3.029**	**136**	**4.571**	**54**	**37**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Allegheny Power	Rodney Phillips	Affirmative	
1	Ameren Services	Kirit S. Shah	Negative	View
1	American Electric Power	Paul B. Johnson	Abstain	
1	American Transmission Company, LLC	Jason Shaver	Negative	View
1	Arizona Public Service Co.	Robert D Smith	Negative	View
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	View
1	Avista Corp.	Scott Kinney	Negative	View
1	BC Transmission Corporation	Gordon Rawlings	Negative	View

1	Beaches Energy Services	Joseph S. Stonecipher	Negative	View
1	Black Hills Corp	Eric Egge	Negative	
1	Bonneville Power Administration	Donald S. Watkins	Negative	View
1	CenterPoint Energy	Paul Rocha	Abstain	
1	Central Maine Power Company	Brian Conroy		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Vero Beach	Randall McCamish	Negative	View
1	Clark Public Utilities	Jack Stamper	Abstain	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	View
1	Dairyland Power Coop.	Robert W. Roddy		
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	John K Loftis	Abstain	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	E.ON U.S.	Larry Monday		
1	East Kentucky Power Coop.	George S. Carruba	Negative	View
1	Edison Electric Institute	David Batz	Abstain	
1	Empire District Electric Co.	Ralph Frederick Meyer	Affirmative	
1	Entergy Corporation	George R. Bartlett	Affirmative	
1	FirstEnergy Energy Delivery	Robert Martinko	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Gainesville Regional Utilities	Luther E. Fair	Affirmative	
1	GDS Associates, Inc.	Claudiu Cadar	Abstain	
1	Georgia Transmission Corporation	Harold Taylor, II	Affirmative	
1	Great River Energy	Gordon Pietsch		
1	Hoosier Energy Rural Electric Cooperative, Inc.	Robert Solomon		
1	Hydro One Networks, Inc.	Ajay Garg	Negative	View
1	Idaho Power Company	Ronald D. Schellberg	Negative	View
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JEA	Ted E Hobson	Negative	View
1	Kansas City Power & Light Co.	Michael Gammon	Negative	
1	Keys Energy Services	Stan T. Rzad	Negative	View
1	Lake Worth Utilities	Walt Gill	Negative	View
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lee County Electric Cooperative	John W Delucca	Abstain	
1	Lincoln Electric System	Doug Bantam	Abstain	
1	Long Island Power Authority	Robert Ganley	Abstain	
1	Manitoba Hydro	Michelle Rheault	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	View
1	National Grid	Saurabh Saksena		
1	Nebraska Public Power District	Richard L. Koch	Abstain	
1	Nevada Power Co.	James McMorran	Negative	View
1	New York Power Authority	Arnold J. Schuff	Abstain	
1	Northeast Utilities	David H. Boguslawski	Abstain	
1	Northern Indiana Public Service Co.	Kevin M Largura	Negative	
1	NorthWestern Energy	John Canavan	Negative	View
1	Ohio Valley Electric Corp.	Robert Mattey	Negative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Abstain	
1	Omaha Public Power District	Douglas G Peterchuck	Abstain	
1	Orlando Utilities Commission	Brad Chase	Negative	View
1	Otter Tail Power Company	Daryl Hanson	Negative	
1	Pacific Gas and Electric Company	Chifong L. Thomas	Negative	View
1	PacifiCorp	Colt Norrish	Affirmative	
1	PECO Energy	Ronald Schloendorn	Affirmative	
1	Platte River Power Authority	John C. Collins	Negative	View
1	Portland General Electric Co.	Frank F. Afranji	Negative	View
1	Potomac Electric Power Co.	Richard J Kafka	Affirmative	
1	PowerSouth Energy Cooperative	Larry D. Avery	Negative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Progress Energy Carolinas	Sammy Roberts	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Negative	View
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Public Utility District No. 1 of Chelan County	Chad Bowman		
1	Puget Sound Energy, Inc.	Catherine Koch	Negative	View

1	Rochester Gas and Electric Corp.	John C Allen	Negative	
1	Sacramento Municipal Utility District	Tim Kelley	Negative	View
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Linda Brown	Affirmative	
1	Santee Cooper	Terry L. Blackwell	Negative	
1	SCE&G	Henry Delk, Jr.	Affirmative	
1	Seattle City Light	Pawel Krupa	Negative	View
1	South Texas Electric Cooperative	Richard McLeon	Abstain	
1	Southern California Edison Co.	Dana Cabbell	Negative	View
1	Southern Company Services, Inc.	Horace Stephen Williamson	Affirmative	
1	Southern Illinois Power Coop.	William G. Hutchison	Affirmative	
1	Southwest Transmission Cooperative, Inc.	James L. Jones	Affirmative	
1	Southwestern Power Administration	Gary W Cox	Abstain	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Affirmative	
1	Tampa Electric Co.	Beth Young	Negative	
1	Tennessee Valley Authority	Larry Akens	Negative	View
1	Tri-State G & T Association, Inc.	Keith V. Carman	Negative	View
1	Tucson Electric Power Co.	John Tolo	Negative	View
1	United Illuminating Co.	Jonathan Appelbaum	Negative	View
1	Westar Energy	Allen Klassen	Abstain	
1	Western Area Power Administration	Brandy A Dunn	Negative	View
1	Xcel Energy, Inc.	Gregory L Pieper		
2	Alberta Electric System Operator	Mark B Thompson	Abstain	
2	BC Hydro	Venkataramakrishnan Vinnakota	Negative	View
2	California ISO	Gregory Van Pelt	Negative	View
2	Electric Reliability Council of Texas, Inc.	Chuck B Manning	Negative	View
2	Independent Electricity System Operator	Kim Warren	Negative	View
2	ISO New England, Inc.	Kathleen Goodman	Negative	
2	Midwest ISO, Inc.	Jason L Marshall	Negative	View
2	New Brunswick System Operator	Alden Briggs	Affirmative	
2	New York Independent System Operator	Gregory Campoli	Negative	
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
2	Southwest Power Pool	Charles H Yeung	Negative	
3	Alabama Power Company	Richard J. Mandes	Affirmative	
3	Allegheny Power	Bob Reeping	Affirmative	
3	Ameren Services	Mark Peters	Negative	
3	American Electric Power	Raj Rana	Abstain	
3	APS	Steven Norris	Negative	View
3	Atlantic City Electric Company	James V. Petrella	Affirmative	
3	Avista Corp.	Robert Lafferty	Negative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Blue Ridge Power Agency	Duane S. Dahlquist	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Negative	View
3	City of Bartow, Florida	Matt Culverhouse	Negative	
3	City of Clewiston	Lynne Mila		
3	City of Farmington	Linda R. Jacobson	Abstain	
3	City of Green Cove Springs	Gregg R Griffin	Negative	View
3	City of Leesburg	Phil Janik	Negative	
3	Cleco Corporation	Michelle A Corley	Negative	
3	ComEd	Bruce Krawczyk	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	View
3	Consumers Energy	David A. Lapinski	Abstain	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Edwin Les Barrow	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources Services	Michael F Gildea	Abstain	
3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	
3	East Kentucky Power Coop.	Sally Witt	Negative	View
3	Entergy	Joel T Plessinger		
3	FirstEnergy Solutions	Kevin Querry	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Negative	
3	Florida Power & Light Co.	W. R. Schoneck	Negative	View
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Gainesville Regional Utilities	Kenneth Simmons	Negative	
3	Georgia Power Company	Anthony L Wilson	Affirmative	

3	Georgia System Operations Corporation	R Scott S. Barfield-McGinnis	Affirmative	
3	Great River Energy	Sam Kokkinen		
3	Gulf Power Company	Gwen S Frazier	Affirmative	
3	Hydro One Networks, Inc.	David L Kiguel	Negative	View
3	JEA	Garry Baker	Negative	
3	Kansas City Power & Light Co.	Charles Locke	Negative	
3	Kissimmee Utility Authority	Gregory David Woessner	Negative	View
3	Lakeland Electric	Mace Hunter	Abstain	
3	Lincoln Electric System	Bruce Merrill		
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	View
3	Manitoba Hydro	Greg C Parent	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	
3	Mississippi Power	Don Horsley	Affirmative	
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Affirmative	
3	Muscatine Power & Water	John S Bos	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	Marilyn Brown	Abstain	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Abstain	
3	Northern Indiana Public Service Co.	William SeDoris	Negative	
3	Ocala Electric Utility	David T. Anderson	Negative	
3	Orlando Utilities Commission	Ballard Keith Mutters	Affirmative	
3	PacifiCorp	John Apperson	Affirmative	
3	PECO Energy an Exelon Co.	Vincent J. Catania	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz		
3	Potomac Electric Power Co.	Robert Reuter		
3	Progress Energy Carolinas	Sam Waters		
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Public Utility District No. 2 of Grant County	Greg Lange	Negative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Negative	View
3	Salt River Project	John T. Underhill		
3	San Diego Gas & Electric	Scott Peterson		
3	Santee Cooper	Zack Dusenbury	Negative	
3	Seattle City Light	Dana Wheelock	Negative	View
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	
3	South Carolina Electric & Gas Co.	Hubert C. Young	Affirmative	
3	Southern California Edison Co.	David Schiada	Negative	View
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L Donahey	Negative	View
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Negative	View
3	Wisconsin Electric Power Marketing	James R. Keller		
3	Xcel Energy, Inc.	Michael Ibold	Negative	View
4	American Municipal Power - Ohio	Kevin Koloini	Abstain	
4	City of Clewiston	Kevin McCarthy		
4	City of New Smyrna Beach Utilities Commission	Timothy Beyrle	Negative	View
4	Consumers Energy	David Frank Ronk	Abstain	
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	Detroit Edison Company	Daniel Herring		
4	Florida Municipal Power Agency	Frank Gaffney	Negative	View
4	Fort Pierce Utilities Authority	Thomas W. Richards	Negative	View
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Abstain	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean		
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Negative	View
4	Seattle City Light	Hao Li	Negative	View
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Abstain	
5	AEP Service Corp.	Brock Ondayko	Abstain	
5	Amerenue	Sam Dwyer	Negative	
5	APS	Mel Jensen	Negative	View

5	Avista Corp.	Edward F. Groce	Negative	View
5	BC Hydro and Power Authority	Clement Ma	Negative	View
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	View
5	Chelan County Public Utility District #1	John Yale		
5	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Max Emrick	Affirmative	
5	Cleco Power	Stephanie Huffman	Negative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Negative	View
5	Consumers Energy	James B Lewis	Abstain	
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	CPS Energy	Robert B Stevens	Affirmative	
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	East Kentucky Power Coop.	Stephen Ricker	Negative	View
5	Energy Northwest - Columbia Generating Station	Doug Ramey	Affirmative	
5	Entergy Corporation	Stanley M Jaskot	Affirmative	
5	Exelon Nuclear	Michael Korchynsky	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Negative	View
5	Great River Energy	Cynthia E Sulzer		
5	Kansas City Power & Light Co.	Scott Heidtbrink		
5	Kissimmee Utility Authority	Mike Blough	Negative	
5	Lakeland Electric	Thomas J Trickey		
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Louisville Gas and Electric Co.	Charlie Martin	Negative	View
5	Manitoba Hydro	S N Fernando	Affirmative	
5	MEAG Power	Steven Grego	Affirmative	
5	MidAmerican Energy Co.	Christopher Schneider	Negative	View
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Gerald Mannarino	Abstain	
5	Northern Indiana Public Service Co.	Michael K Wilkerson	Negative	
5	Omaha Public Power District	Mahmood Z. Safi	Abstain	
5	Orlando Utilities Commission	Richard Kinas	Negative	View
5	Pacific Gas and Electric Company	Richard J. Padilla		
5	PacifiCorp	Sandra L. Shaffer	Affirmative	
5	Portland General Electric Co.	Gary L Tingley		
5	PowerSouth Energy Cooperative	Tim Hattaway	Abstain	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	
5	PSEG Power LLC	Jerzy A Slusarz		
5	RRI Energy	Thomas J. Bradish	Affirmative	
5	Sacramento Municipal Utility District	Bethany Wright	Negative	View
5	Salt River Project	Glen Reeves	Affirmative	
5	Santee Cooper	Lewis P Pierce	Negative	
5	Seattle City Light	Michael J. Haynes	Negative	View
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	
5	South Carolina Electric & Gas Co.	Richard Jones	Affirmative	
5	South Mississippi Electric Power Association	Jerry W Johnson		
5	Tampa Electric Co.	RJames Rocha	Negative	
5	Tenaska, Inc.	Scott M. Helyer	Affirmative	
5	Tennessee Valley Authority	George T. Ballew	Negative	View
5	Tri-State G & T Association, Inc.	Barry Ingold	Negative	
5	U.S. Army Corps of Engineers Northwestern Division	Karl Bryan	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer P.E.	Abstain	
5	Wisconsin Electric Power Co.	Linda Horn		
5	Wisconsin Public Service Corp.	Leonard Rentmeester	Negative	View
5	Xcel Energy, Inc.	Liam Noailles	Negative	View
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Negative	View
6	Arizona Public Service Co.	Justin Thompson	Negative	View
6	Bonneville Power Administration	Brenda S. Anderson	Negative	View
6	Cleco Power LLC	Robert Hirchak	Negative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Negative	View
6	Constellation Energy Commodities Group	Brenda Powell	Abstain	
6	Dominion Resources, Inc.	Louis S Slade	Abstain	

6	Duke Energy Carolina	Walter Yeager	Affirmative	
6	Entergy Services, Inc.	Terri F Benoit	Affirmative	
6	Exelon Power Team	Pulin Shah	Affirmative	
6	FirstEnergy Solutions	Mark S Travaglianti	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	View
6	Florida Municipal Power Pool	Thomas E Washburn	Negative	View
6	Florida Power & Light Co.	Silvia P Mitchell		
6	Great River Energy	Donna Stephenson		
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	
6	Lakeland Electric	Paul Shipps	Negative	View
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Louisville Gas and Electric Co.	Daryn Barker	Negative	View
6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	MidAmerican Energy Co.	Dennis Kimm	Negative	View
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	
6	NRG Energy, Inc.	Alan R. Johnson	Abstain	
6	Omaha Public Power District	David Ried	Abstain	
6	PacifiCorp	Scott L Smith	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Negative	View
6	Portland General Electric Co.	John Jamieson	Negative	
6	PPL EnergyPlus LLC	Mark A Heimbach	Affirmative	
6	Progress Energy	John T Sturgeon	Affirmative	
6	PSEG Energy Resources & Trade LLC	James D. Hebson	Abstain	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	RRI Energy	Trent Carlson	Affirmative	
6	Salt River Project	Mike Hummel	Affirmative	
6	Santee Cooper	Suzanne Ritter	Negative	
6	Seattle City Light	Dennis Sismaet	Negative	View
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Joann Wehle	Negative	
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	View
6	Western Area Power Administration - UGP Marketing	John Stonebarger		
6	Xcel Energy, Inc.	David F. Lemmons	Negative	View
8		James A Maenner	Negative	View
8		Roger C Zaklukiewicz	Negative	
8		Edward C Stein	Affirmative	
8	JDRJC Associates	Jim D. Cyrulewski	Negative	
8	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	California Energy Commission	William Mitchell Chamberlain		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Negative	View
9	North Carolina Utilities Commission	Kimberly J. Jones		
9	Oregon Public Utility Commission	Jerome Murray	Negative	View
9	Utah Public Service Commission	Ric Campbell	Affirmative	
10	Florida Reliability Coordinating Council	Linda Campbell	Abstain	
10	Midwest Reliability Organization	James D Burley	Negative	View
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council, Inc.	Guy V. Zito	Negative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	View
10	SERC Reliability Corporation	Carter B Edge	Affirmative	
10	Southwest Power Pool Regional Entity	Stacy Dochoda	Affirmative	
10	Texas Reliability Entity	Larry D Grimm	Negative	View
10	Western Electricity Coordinating Council	Louise McCarren	Negative	View

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Standards Announcement

Initial Ballot and Nonbinding Poll Results

Now available at: https://standards.nerc.net/Ballots.aspx

Project 2010-10 – FAC Order 729

The initial ballot and nonbinding poll of VRFs and VSLs for FAC-013-2— Planning Transfer Capability and its Implementation Plan ended on November 3, 2010.

Voting statistics are listed below, and the Ballot Results Web page provides a link to the detailed results:

Quorum: 88.54%

Approval: 39.85%

Since there were negative ballots that included a comment, these results are not final. A successive ballot must be conducted.

Violation Risk Factor (VRF) and Violation Severity Level (VSL) Non-binding Poll Results

For the non-binding poll of VRFs and VSLs proposed for FAC-013-2 — Planning Transfer Capability, 87% of those who registered to participate provided an opinion; 55% of those who provided an opinion indicated support for the VRFs and VSLs that were proposed.

Next Steps

The drafting team will post its consideration of all comments (those submitted with a comment form, and those submitted with a ballot) and conforming changes to the standard.

Project Background

In Order 729, FERC ruled that the ATC standards developed in Project 2006-07 did not completely address the topics covered in FAC-012 and -013, and that they did not fully address the associated directives from Order 693. Accordingly, FERC denied the portions of the implementation plan that would have retired these standards, and instead directed NERC to use the standards development process to make changes to the FAC standards and file those changes with FERC no later than 60 days prior to the effective date of the standards, which is April 1, 2011 (requiring the proposed changes to be filed on or before January 31, 2011).

Further details are available on the project page:
http://www.nerc.com/filez/standards/Project2010-10_FAC_Order_729.html

Applicability of Standards in Project

Planning Coordinators

Standards Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Monica Benson,
Standards Process Administrator, at monica.benson@nerc.net or at 609.452.8060.

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Consideration of Opinions on Nonbinding Poll of VRFs and VSLs for FAC-013-2 - Assessment of Planning Transfer Capability for the Near-Term Transmission Planning Horizon — Project 2010-10

Date of Poll: October 20-November 3, 2010

Summary Consideration: A non-binding poll of VRFs and VSLs for FAC-013 was conducted from October 20 through November 3, 2010; the poll did achieve a quorum - 87% of those who registered to participate provided an opinion, however only 55% of those who provided an opinion indicated support for the VRFs and VSLs that were proposed.

The majority of negative opinions indicated that the VSLs for Requirement R1 contained an overlap or needed additional gradation. The SDT explained that Requirement R1 had been extensively revised and therefore the SDT had modified the VSLs to be consistent with the new Requirement R1. The SDT modified the Requirement R1 Lower and Moderate VSLs to eliminate the overlap. They now read "The Planning Coordinator has a Transfer Capability Methodology but failed to address one or two of the items listed in Requirement R1 Part 1.4"; "The Planning Coordinator has a Transfer Capability Methodology but failed to incorporate one of the Requirement R1 Parts 1.1, 1.2, 1.3, and 1.5 OR The Planning Coordinator has a Transfer Capability Methodology but failed to address three of the items listed in Requirement R1 Part 1.4." A High VSL was assigned for failure to address four of the items listed in Requirement R1 Part 1.4 – and a Severe was assigned for failure to address more than four of the items listed in Requirement R1 Part 1.4. The SDT believes that the gradations are now appropriate for each part of Requirement R1.

Several of the negative opinions questioned whether Planning Transfer Capability (PTC) was intended to be analogous with a total transfer capability or an available transfer capability for the long term. In addition some of the negative opinions indicated that PTC was not needed. The SDT explained that the PTC definition had been deleted based on industry comments and the concept of transfer capability assessment in the Near-Term Planning Horizon had been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. In addition, the standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers, not specific transfer capability values.

A few of the negative opinions indicated the scope of the standard was unclear because it did not specify which entities, lines or paths it applied to. They further stated that they believed this standard should specifically apply to a Planning Authority required by its Regional Reliability Organization to establish interregional and intra-regional Transfer Capabilities. The SDT explained that the purpose of the standard was to require Planning Coordinators to have a method for analysis of the ability to transfer energy (beyond 13 months) to identify potential future weaknesses and limiting facilities. The standard allows each Planning Coordinator to determine the method (transfer level, paths, contingencies,…) that best allows them to identify potential future weaknesses and limiting facilities according to their understanding of the needs of the system. The SDT further explained that the commission stated in Order 693 paragraph 790 "The Commission does not believe that the regional reliability organization should be able to decide the type of entity to which this Reliability Standard applies. …" and the SDT agrees.

The SDT believes there is a reliability related need for the transfer capability assessment to be conducted. The SDT does not believe the TPL standards adequately cover the need at this time.

A couple of the negative opinions indicated that Requirement R1 Part R1.4 was vague as to the requirement that assumptions and criteria to calculate PTCs be as, or more limiting than the assumptions and criteria used in operating horizon. The SDT explained that the Requirement R1 Part 1.4 (now Requirement R1 Part 1.3) had been revised to require that the assumptions and criteria used to perform the assessment are consistent with the Planning Coordinator's planning practices because the purpose of the standard is to support planning for reliable system operation in the planning horizon.

If you feel that the drafting team overlooked your comments, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Herbert Schrayshuen, at 609-452-8060 or at herb. schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

Segment	Company	Balloter	Opinion	Comments
1	Ameren Services	Kirit S. Shah	Negative	We believe the VSLs for R1 should be expanded to include more gradations. Failure to include one element from Parts 1.2 through 1.5 should be a Lower VSL. Failure to include two elements should be a Moderate VSL. Failure to include three elements should be a High VSL. Failure to include four elements should be a Severe VSL.
Response: Requirement R1 has been extensively revised; the SDT has modified the VSLs to be consistent with the new Requirement R1 and your comments. The SDT has modified the Requirement R1 Lower and Moderate VSLs to "The Planning Coordinator has a Transfer Capability Methodology but failed to address one or two of the items listed in Requirement R1 Part 1.4"; "The Planning Coordinator has a Transfer Capability Methodology but failed to incorporate one of the Requirement R1 Parts 1.1, 1.2, 1.3, and 1.5 OR The Planning Coordinator has a Transfer Capability Methodology but failed to address more than two of the items listed in Requirement R1 Part 1.4." The SDT feels that the gradations are now appropriate for each sub-part.				
1	Avista Corp.	Scott Kinney	Negative	If the PC has a PTCMD but failed to address two of the items listed in Requirement R1, Part 1.1, they would meet the language of both the Lower and the Moderate VSL. We suggest you change the second part of the Moderate VSL to read "The Planning Coordinator has a PTCMD but failed to address three or more of the items listed in Requirement 1, Part 1.1"
Response: Requirement R1 has been extensively revised; the SDT has modified the VSLs to be consistent with the new Requirement R1 and your comments. The SDT has modified the Requirement R1 Lower and Moderate VSLs to "The Planning Coordinator has a Transfer Capability Methodology but failed to				

[1] The appeals process is in the Standard Processes Manual.

Segment	Company	Balloter	Opinion	Comments
address one or two of the items listed in Requirement R1 Part 1.4"; "The Planning Coordinator has a Transfer Capability Methodology but failed to incorporate one of the Requirement R1 Parts 1.1, 1.2, 1.3, and 1.5 OR The Planning Coordinator has a Transfer Capability Methodology but failed to address three of the items listed in Requirement R1 Part 1.4." A High VSL was assigned for failure to address four of the items listed in Requirement R1 Part 1.4 – and a Severe was assigned for failure to address more than four of the items listed in Requirement R1 Part 1.4. The SDT feels that the gradations are now appropriate for each sub-part.				
1	Black Hills Corp	Eric Egge	Negative	We agree with the proposed VRFs, but there is a problem with the VSL for R1. As proposed there is overlap between the Lower and Moderate VSL for R1. The Lower VSL reads: The Planning Coordinator has a PTCMD but failed to address one or two of the items listed in Requirement R1, Part 1.1. The second part of the Moderate VSL reads: The Planning Coordinator has a PTCMD but failed to address two or more of the items listed in Requirement 1, Part 1.1 If the PC has a PTCMD but failed to address two of the items listed in Requirement R1, Part 1.1, they would meet the language of both the Lower and the Moderate VSL. We suggest you change the second part of the Moderate VSL to read The Planning Coordinator has a PTCMD but failed to address three or more of the items listed in Requirement 1, Part 1.1
Response: Requirement R1 has been extensively revised; the SDT has modified the VSLs to be consistent with the new Requirement R1 and your comments. The SDT has modified the Requirement R1 Lower and Moderate VSLs to "The Planning Coordinator has a Transfer Capability Methodology but failed to address one or two of the items listed in Requirement R1 Part 1.4"; "The Planning Coordinator has a Transfer Capability Methodology but failed to incorporate one of the Requirement R1 Parts 1.1, 1.2, 1.3, and 1.5 OR The Planning Coordinator has a Transfer Capability Methodology but failed to address three of the items listed in Requirement R1 Part 1.4." A High VSL was assigned for failure to address four of the items listed in Requirement R1 Part 1.4 – and a Severe was assigned for failure to address more than four of the items listed in Requirement R1 Part 1.4.The SDT feels that the gradations are now appropriate for each sub-part.				

Segment	Company	Balloter	Opinion	Comments
1	JEA	Ted E Hobson	Negative	Concerning the VSL descriptions/violation triggers: recommend changing Moderate VSL (second part) to: The Planning Coordinator has a PTCMD but failed to address three or more of the items listed in Requirement R1, Part 1.1. The changes in severity levels for R2, R3, and R5 should be in multiples of 30 days, not in multiples of 10 days, which seems haphazardly chosen and severe for requirements that all have Lower VRFs. Similarly, R4 should be in multiples of 25% rather than 5%, particularly since there should not be a need to calculate very many PTCs because they should only be calculated for reliability enhancement reasons. Finally, the word "notified" in each VSL for R5 should be replaced with "made available to" in order to be consistent with the wording in R5
Response: Requirement R1 has been extensively revised; the SDT has modified the VSLs to be consistent with the new Requirement R1 and your comments. The SDT has modified the Requirement R1 Lower and Moderate VSLs to "The Planning Coordinator has a Transfer Capability Methodology but failed to address one or two of the items listed in Requirement R1 Part 1.4"; "The Planning Coordinator has a Transfer Capability Methodology but failed to incorporate one of the Requirement R1 Parts 1.1, 1.2, 1.3, and 1.5 OR The Planning Coordinator has a Transfer Capability Methodology but failed to address three of the items listed in Requirement R1 Part 1.4." A High VSL was assigned for failure to address four of the items listed in Requirement R1 Part 1.4 – and a Severe was assigned for failure to address more than four of the items listed in Requirement R1 Part 1.4.The SDT feels that the gradations are now appropriate for each sub-part. The SDT chose increments for R2, R3 and R5 with increments that vary depending on the content of the requirement. R4 in the initial draft of FAC-013-2 has been replaced; the new VSLs for R4 do not use multiples. The SDT has modified Requirement R5 VSL to address your concern. The SDT feels that the gradations are now appropriate for each sub-part.				
1	Portland General Electric Co.	Frank F. Afranji	Affirmative	PGE agrees with the proposed VRFs, but there is a problem with the VSL for R1. As proposed there is overlap between the Lower and Moderate VSL for R1. The Lower VSL reads: The Planning Coordinator has a PTCMD but failed to address one or two of the items listed in Requirement R1, Part 1.1. The second part of the Moderate VSL reads: The Planning Coordinator has a PTCMD but failed to address two or more of the items listed in Requirement 1, Part 1.1 If the PC has a PTCMD but failed to address two of the items listed in Requirement R1, Part 1.1, they would meet the language of both the Lower and the Moderate VSL. We suggest you change the second part of the Moderate VSL to read The Planning Coordinator has a PTCMD but failed to address three or more of the items listed in Requirement 1, Part 1.1"

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1	Public Service Company of New Mexico	Laurie Williams	Negative	We agree with the proposed VRFs, but there is a problem with the VSL for R1. As proposed there is overlap between the Lower and Moderate VSL for R1. The Lower VSL reads: The Planning Coordinator has a PTCMD but failed to address one or two of the items listed in Requirement R1, Part 1.1. The second part of the Moderate VSL reads: The Planning Coordinator has a PTCMD but failed to address two or more of the items listed in Requirement 1, Part 1.1 If the PC has a PTCMD but failed to address two of the items listed in Requirement R1, Part 1.1, they would meet the language of both the Lower and the Moderate VSL. We suggest you change the second part of the Moderate VSL to read The Planning Coordinator has a PTCMD but failed to address three or more of the items listed in Requirement 1, Part 1.1
Response: Requirement R1 has been extensively revised; the SDT has modified the VSLs to be consistent with the new Requirement R1 and your comments. The SDT has modified the Requirement R1 Lower and Moderate VSLs to "The Planning Coordinator has a Transfer Capability Methodology but failed to address one or two of the items listed in Requirement R1 Part 1.4"; "The Planning Coordinator has a Transfer Capability Methodology but failed to incorporate one of the Requirement R1 Parts 1.1, 1.2, 1.3, and 1.5 OR The Planning Coordinator has a Transfer Capability Methodology but failed to address three of the items listed in Requirement R1 Part 1.4." A High VSL was assigned for failure to address four of the items listed in Requirement R1 Part 1.4 – and a Severe was assigned for failure to address more than four of the items listed in Requirement R1 Part 1.4.The SDT feels that the gradations are now appropriate for each sub-part.				
1	Puget Sound Energy, Inc.	Catherine Koch	Negative	We agree with the proposed VRFs, but there is a problem with the VSL for R1. As proposed there is overlap between the Lower and Moderate VSL for R1. The Lower VSL reads: The Planning Coordinator has a PTCMD but failed to address one or two of the items listed in Requirement R1, Part 1.1. The second part of the Moderate VSL reads: The Planning Coordinator has a PTCMD but failed to address two or more of the items listed in Requirement 1, Part 1.1 If the PC has a PTCMD but failed to address two of the items listed in Requirement R1, Part 1.1, they would meet the language of both the Lower and the Moderate VSL. We suggest you change the second part of the Moderate VSL to read The Planning Coordinator has a PTCMD but failed to address three or more of the items listed in Requirement 1, Part 1.1"

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1	Sacramento Municipal Utility District	Tim Kelley	Negative	The second part of the Moderate VSL reads: The Planning Coordinator has a PTCMD but failed to address two or more of the items listed in Requirement 1, Part 1.1 If the PC has a PTCMD but failed to address two of the items listed in Requirement R1, Part 1.1, they would meet the language of both the Lower and the Moderate VSL. It is suggested that the second part of the Moderate VSL to read The Planning Coordinator has a PTCMD but failed to address THREE or more of the items listed in Requirement 1, Part 1.1"
Response: Requirement R1 has been extensively revised; the SDT has modified the VSLs to be consistent with the new Requirement R1 and your comments. The SDT has modified the Requirement R1 Lower and Moderate VSLs to "The Planning Coordinator has a Transfer Capability Methodology but failed to address one or two of the items listed in Requirement R1 Part 1.4"; "The Planning Coordinator has a Transfer Capability Methodology but failed to incorporate one of the Requirement R1 Parts 1.1, 1.2, 1.3, and 1.5 OR The Planning Coordinator has a Transfer Capability Methodology but failed to address three of the items listed in Requirement R1 Part 1.4." A High VSL was assigned for failure to address four of the items listed in Requirement R1 Part 1.4 – and a Severe was assigned for failure to address more than four of the items listed in Requirement R1 Part 1.4.The SDT feels that the gradations are now appropriate for each sub-part.				
1	Tampa Electric Co.	Beth Young	Negative	The VSLs for R1 Lower and Moderate are inconsistent or contain an error. Recommend changing Moderate VSL (second part) to "The Planning Coordinator has a PTCMD but failed to address three or more of the items listed in Requirement R1, Part 1.1. The High and Severe VSLs for R1 should spell out the numerical 2 and 3 as "two" and "three" for consistency. The changes in severity levels for R2, R3, and R5 should be in multiples of 30 days, not in multiples of 10 days, which seems haphazardly chosen and severe for requirements that all have Lower VRFs. Similarly, R4 should be in multiples of 25% rather than 5%, particularly since there should not be a need to calculate very many PTCs because they should only be calculated for reliability enhancement reasons. Finally, the word "notified" in each VSL for R5 should be replaced with "made available to" in order to be consistent with the wording in R5.
Response: Requirement R1 has been extensively revised; the SDT has modified the VSLs to be consistent with the new Requirement R1 and your comments. The SDT has modified the Requirement R1 Lower and Moderate VSLs to "The Planning Coordinator has a Transfer Capability Methodology but failed to				

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1	Tucson Electric Power Co.	John Tolo	Negative	agree with the proposed VRFs, but there is a problem with the VSL for R1. As proposed there is overlap between the Lower and Moderate VSL for R1. The Lower VSL reads: The Planning Coordinator has a PTCMD but failed to address one or two of the items listed in Requirement R1, Part 1.1. The second part of the Moderate VSL reads: The Planning Coordinator has a PTCMD but failed to address two or more of the items listed in Requirement 1, Part 1.1 If the PC has a PTCMD but failed to address two of the items listed in Requirement R1, Part 1.1, they would meet the language of both the Lower and the Moderate VSL. We suggest you change the second part of the Moderate VSL to read The Planning Coordinator has a PTCMD but failed to address three or more of the items listed in Requirement 1, Part 1.1"
Response: Requirement R1 has been extensively revised; the SDT has modified the VSLs to be consistent with the new Requirement R1 and your comments. The SDT has modified the Requirement R1 Lower and Moderate VSLs to "The Planning Coordinator has a Transfer Capability Methodology but failed to address one or two of the items listed in Requirement R1 Part 1.4"; "The Planning Coordinator has a Transfer Capability Methodology but failed to incorporate one of the Requirement R1 Parts 1.1, 1.2, 1.3, and 1.5 OR The Planning Coordinator has a Transfer Capability Methodology but failed to address three of the items listed in Requirement R1 Part 1.4." A High VSL was assigned for failure to address four of the items listed in Requirement R1 Part 1.4 – and a Severe was assigned for failure to address more than four of the items listed in Requirement R1 Part 1.4.The SDT feels that the gradations are now appropriate for each sub-part.				
2	California ISO	Gregory Van Pelt	Negative	We agree with and support the VRFs, however a revision is needed to the VSL for R1. As currently proposed, there is an overlap (with "two" of the items) appearing in both the Lower and Moderate VSL for R1. If an entity fails to meet "two" of the items listed in requirement R1, Part 1.1, the entity would meet the language currently contained in both the Lower and in the Moderate VSL. We recommend the SDT change the second part of the Moderate VSL to read: "The Planning Coordinator has a PTCMD but failed to address three or more of the items listed in Requirement R1, Part 1.1"
Response: Requirement R1 has been extensively revised; the SDT has modified the VSLs to be consistent with the new Requirement R1 and your comments. The SDT has modified the Requirement R1 Lower and Moderate VSLs to "The Planning Coordinator has a Transfer Capability Methodology but failed to address one or two of the items listed in Requirement R1 Part 1.4"; "The Planning Coordinator has a Transfer Capability Methodology but failed to incorporate				

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2	Midwest ISO, Inc.	Jason L Marshall	Negative	We thank the drafting team for revising these VRFs to be Lower. While we disagree with the need for the standard, we understand that requirements must include a VRF and support the assignment of "Lower" for the VRFs. We believe the VSLs for R1 should be expanded to include more gradations. Failure to include one element from Parts 1.2 through 1.5 should be a Lower VSL. Failure to include two elements should be a Moderate VSL. Failure to include three elements should be a High VSL. Failure to include four elements should be a Severe VSL.
Response: Requirement R1 has been extensively revised; the SDT has modified the VSLs to be consistent with the new Requirement R1 and your comments. The SDT has modified the Requirement R1 Lower and Moderate VSLs to "The Planning Coordinator has a Transfer Capability Methodology but failed to address one or two of the items listed in Requirement R1 Part 1.4"; "The Planning Coordinator has a Transfer Capability Methodology but failed to incorporate one of the Requirement R1 Parts 1.1, 1.2, 1.3, and 1.5 OR The Planning Coordinator has a Transfer Capability Methodology but failed to address three of the items listed in Requirement R1 Part 1.4." A High VSL was assigned for failure to address four of the items listed in Requirement R1 Part 1.4 – and a Severe was assigned for failure to address more than four of the items listed in Requirement R1 Part 1.4. The SDT feels that the gradations are now appropriate for each sub-part.				
3	Florida Power & Light Co.	W. R. Schoneck	Negative	The VSLs for R1 Lower and Moderate are inconsistent or contain an error. Recommend changing Moderate VSL (second part) to "The Planning Coordinator has a PTCMD but failed to address three or more of the items listed in Requirement R1, Part 1.1. The High and Severe VSLs for R1 should spell out the numerical 2 and 3 as "two" and "three" for consistency. The changes in severity levels for R2, R3, and R5 should be in multiples of 30 days, not in multiples of 10 days, which seems haphazardly chosen and severe for requirements that all have Lower VRFs. Similarly, R4 should be in multiples of 25% rather than 5%, particularly since there should not be a need to calculate very many PTCs because they should only be calculated for reliability enhancement reasons. Finally, the word "notified" in each VSL for R5 should be replaced with "made available to" in order to be consistent with the wording in R5.
Response: Requirement R1 has been extensively revised; the SDT has modified the VSLs to be consistent with the new Requirement R1 and your comments. The SDT has modified the Requirement R1 Lower and Moderate VSLs to "The Planning Coordinator has a Transfer Capability Methodology but failed to address one or two of the items listed in Requirement R1 Part 1.4"; "The Planning Coordinator has a Transfer Capability Methodology but failed to incorporate one of the Requirement R1 Parts 1.1, 1.2, 1.3, and 1.5 OR The Planning Coordinator has a Transfer Capability Methodology but failed to address three of the items listed in Requirement R1 Part 1.4." A High VSL was assigned for failure to address four of the items listed in Requirement R1 Part 1.4 – and a Severe				

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3	PNM Resources	Michael Mertz	Negative	PNMR agrees with the proposed VRFs, but there is a problem with the VSL for R1. As proposed there is overlap between the Lower and Moderate VSL for R1. The Lower VSL reads: The Planning Coordinator has a PTCMD but failed to address one or two of the items listed in Requirement R1, Part 1.1. The second part of the Moderate VSL reads: The Planning Coordinator has a PTCMD but failed to address two or more of the items listed in Requirement 1, Part 1.1 If the PC has a PTCMD but failed to address two of the items listed in Requirement R1, Part 1.1, they would meet the language of both the Lower and the Moderate VSL. We suggest you change the second part of the Moderate VSL to read The Planning Coordinator has a PTCMD but failed to address three or more of the items listed in Requirement 1, Part 1.1"
Response: R1 has been extensively revised; the SDT has modified the VSLs to be consistent with the new R1. The SDT has modified the R1 Lower and Moderate VSLs to "The Planning Coordinator has a Transfer Capability Methodology but failed to address one or two of the items listed in requirement R1.4"; "The Planning Coordinator has a Transfer Capability Methodology but failed to incorporate one of the requirements R1.1, R1.2, R1.3, and R1.5 OR The Planning Coordinator has a Transfer Capability Methodology but failed to address three of the items listed in R1.4." A High VSL was assigned for failure to address four of the items listed in Requirement R1 Part 1.4 – and a Severe was assigned for failure to address more than four of the items listed in Requirement R1 Part 1.4.				
3	Sacramento Municipal Utility District	James Leigh-Kendall	Negative	The second part of the Moderate VSL reads: The Planning Coordinator has a PTCMD but failed to address two or more of the items listed in Requirement 1, Part 1.1 If the PC has a PTCMD but failed to address two of the items listed in Requirement R1, Part 1.1, they would meet the language of both the Lower and the Moderate VSL. It is suggested that the second part of the Moderate VSL to read The Planning Coordinator has a PTCMD but failed to address THREE or more of the items listed in Requirement 1, Part 1.1"
Response: Requirement R1 has been extensively revised; the SDT has modified the VSLs to be consistent with the new Requirement R1 and your comments. The SDT has modified the Requirement R1 Lower and Moderate VSLs to "The Planning Coordinator has a Transfer Capability Methodology but failed to address one or two of the items listed in Requirement R1 Part 1.4"; "The Planning Coordinator has a Transfer Capability Methodology but failed to incorporate one of the Requirement R1 Parts 1.1, 1.2, 1.3, and 1.5 OR The Planning Coordinator has a Transfer Capability Methodology but failed to address three of the items listed in Requirement R1 Part 1.4." A High VSL was assigned for failure to address four of the items listed in Requirement R1 Part 1.4 – and a Severe was assigned for failure to address more than four of the items listed in Requirement R1 Part 1.4.The SDT feels that the gradations are now appropriate for each sub-part.				

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4	Sacramento Municipal Utility District	Mike Ramirez	Negative	The second part of the Moderate VSL reads: The Planning Coordinator has a PTCMD but failed to address two or more of the items listed in Requirement 1, Part 1.1 If the PC has a PTCMD but failed to address two of the items listed in Requirement R1, Part 1.1, they would meet the language of both the Lower and the Moderate VSL. It is suggested that the second part of the Moderate VSL to read The Planning Coordinator has a PTCMD but failed to address THREE or more of the items listed in Requirement 1, Part 1.1"
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5	Louisville Gas and Electric Co.	Charlie Martin	Negative	LG&E and KU Energy support the comments submitted by the Midwest ISO
Response: Requirement R1 has been extensively revised; the SDT has modified the VSLs to be consistent with the new Requirement R1 and your comments. The SDT has modified the Requirement R1 Lower and Moderate VSLs to "The Planning Coordinator has a Transfer Capability Methodology but failed to address one or two of the items listed in Requirement R1 Part 1.4"; "The Planning Coordinator has a Transfer Capability Methodology but failed to incorporate one of the Requirement R1 Parts 1.1, 1.2, 1.3, and 1.5 OR The Planning Coordinator has a Transfer Capability Methodology but failed to address three of the items listed in Requirement R1 Part 1.4." A High VSL was assigned for failure to address four of the items listed in Requirement R1 Part 1.4 – and a Severe was assigned for failure to address more than four of the items listed in Requirement R1 Part 1.4.The SDT feels that the gradations are now appropriate for each sub-part.				
5	RRI Energy	Thomas J. Bradish	Negative	We agree with the proposed VRFs, but there is a problem with the VSL for R1. As proposed there is overlap between the Lower and Moderate VSL for R1. The Lower VSL reads: The Planning Coordinator has a PTCMD but failed to address one or two of the items listed in Requirement R1, Part 1.1. The second part of the Moderate VSL reads: The Planning Coordinator has a PTCMD but failed to address two or more of the items listed in Requirement 1, Part 1.1 If the PC has a PTCMD but failed to address two of the items listed in Requirement R1, Part 1.1, they would meet the language of both the Lower and the Moderate VSL. We suggest you change the second part of the Moderate VSL to read The Planning Coordinator has a PTCMD but failed to address three or more of the items listed in Requirement 1, Part 1.1"
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5	Sacramento Municipal Utility District	Bethany Wright	Negative	The second part of the Moderate VSL reads: The Planning Coordinator has a PTCMD but failed to address two or more of the items listed in Requirement 1, Part 1.1 If the PC has a PTCMD but failed to address two of the items listed in Requirement R1, Part 1.1, they would meet the language of both the Lower and the Moderate VSL. It is suggested that the second part of the Moderate VSL to read The Planning Coordinator has a PTCMD but failed to address THREE or more of the items listed in Requirement 1, Part 1.1"
Response: Requirement R1 has been extensively revised; the SDT has modified the VSLs to be consistent with the new Requirement R1 and your comments. The SDT has modified the Requirement R1 Lower and Moderate VSLs to "The Planning Coordinator has a Transfer Capability Methodology but failed to address one or two of the items listed in Requirement R1 Part 1.4"; "The Planning Coordinator has a Transfer Capability Methodology but failed to incorporate one of the Requirement R1 Parts 1.1, 1.2, 1.3, and 1.5 OR The Planning Coordinator has a Transfer Capability Methodology but failed to address three of the items listed in Requirement R1 Part 1.4." A High VSL was assigned for failure to address four of the items listed in Requirement R1 Part 1.4 – and a Severe was assigned for failure to address more than four of the items listed in Requirement R1 Part 1.4.				
6	Ameren Energy Marketing Co.	Jennifer Richardson	Negative	We believe the VSLs for R1 should be expanded to include more gradations. Failure to include one element from Parts 1.2 through 1.5 should be a Lower VSL. Failure to include two elements should be a Moderate VSL. Failure to include three elements should be a High VSL. Failure to include four elements should be a Severe VSL.
Response: Requirement R1 has been extensively revised; the SDT has modified the VSLs to be consistent with the new Requirement R1 and your comments. The SDT has modified the Requirement R1 Lower and Moderate VSLs to "The Planning Coordinator has a Transfer Capability Methodology but failed to address one or two of the items listed in Requirement R1 Part 1.4"; "The Planning Coordinator has a Transfer Capability Methodology but failed to incorporate one of the Requirement R1 Parts 1.1, 1.2, 1.3, and 1.5 OR The Planning Coordinator has a Transfer Capability Methodology but failed to address three of the items listed in Requirement R1 Part 1.4." A High VSL was assigned for failure to address four of the items listed in Requirement R1 Part 1.4 – and a Severe was assigned for failure to address more than four of the items listed in Requirement R1 Part 1.4.The SDT feels that the gradations are now appropriate for each sub-part.				

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6	RRI Energy	Trent Carlson	Negative	We agree with the proposed VRFs, but there is a problem with the VSL for R1. As proposed there is overlap between the Lower and Moderate VSL for R1. The Lower VSL reads: The Planning Coordinator has a PTCMD but failed to address one or two of the items listed in Requirement R1, Part 1.1. The second part of the Moderate VSL reads: The Planning Coordinator has a PTCMD but failed to address two or more of the items listed in Requirement 1, Part 1.1 If the PC has a PTCMD but failed to address two of the items listed in Requirement R1, Part 1.1, they would meet the language of both the Lower and the Moderate VSL. We suggest you change the second part of the Moderate VSL to read The Planning Coordinator has a PTCMD but failed to address three or more of the items listed in Requirement 1, Part 1.1
Response: Requirement R1 has been extensively revised; the SDT has modified the VSLs to be consistent with the new Requirement R1 and your comments. The SDT has modified the Requirement R1 Lower and Moderate VSLs to "The Planning Coordinator has a Transfer Capability Methodology but failed to address one or two of the items listed in Requirement R1 Part 1.4"; "The Planning Coordinator has a Transfer Capability Methodology but failed to incorporate one of the Requirement R1 Parts 1.1, 1.2, 1.3, and 1.5 OR The Planning Coordinator has a Transfer Capability Methodology but failed to address three of the items listed in Requirement R1 Part 1.4." A High VSL was assigned for failure to address four of the items listed in Requirement R1 Part 1.4 – and a Severe was assigned for failure to address more than four of the items listed in Requirement R1 Part 1.4.				
6	Seattle City Light	Dennis Sismaet	Negative	As proposed there is overlap between the Lower and Moderate VSL for R1. The Lower VSL reads: The Planning Coordinator has a PTCMD but failed to address one or two of the items listed in Requirement R1, Part 1.1. The second part of the Moderate VSL reads: The Planning Coordinator has a PTCMD but failed to address two or more of the items listed in Requirement 1, Part 1.1 If the PC has a PTCMD but failed to address two of the items listed in Requirement R1, Part 1.1, they would meet the language of both the Lower and the Moderate VSL. We suggest you change the second part of the Moderate VSL to read The Planning Coordinator has a PTCMD but failed to address three or more of the items listed in Requirement 1, Part 1.1"
Response: Requirement R1 has been extensively revised; the SDT has modified the VSLs to be consistent with the new Requirement R1 and your comments. The SDT has modified the Requirement R1 Lower and Moderate VSLs to "The Planning Coordinator has a Transfer Capability Methodology but failed to address one or two of the items listed in Requirement R1 Part 1.4"; "The Planning Coordinator has a Transfer Capability Methodology but failed to incorporate one of the Requirement R1 Parts 1.1, 1.2, 1.3, and 1.5 OR The Planning Coordinator has a Transfer Capability Methodology but failed to address three of the items listed in Requirement R1 Part 1.4." A High VSL was assigned for failure to address four of the items listed in Requirement R1 Part 1.4 – and a Severe was assigned for failure to address more than four of the items listed in Requirement R1 Part 1.4.				

Segment	Company	Balloter	Opinion	Comments
10	Texas Reliability Entity	Larry D Grimm	Negative	The VSL descriptions are not properly coordinated. For R1, the Lower VSL says “failed to address one or two” while the Moderate VSL, latter part, says “failed to address two or more.” As written, failure to address two items would fall into both Lower and Moderate VSLs. We recommend the Moderate VSL be revised to say “three or more.” For R3, a gap exists between Moderate and High. The Moderate VSL says “after 60 calendar days, but no more than 70 calendar days” while High says “after 80 calendar days.” There is a gap between 71 and 80 days. We recommend the High VSL be revised to say “after 70 calendar days,” which is consistent with the High VSL for R5.
Response: Requirement R1 has been extensively revised; the SDT has modified the VSLs to be consistent with the new Requirement R1 and your comments. The SDT has modified the Requirement R1 Lower and Moderate VSLs to “The Planning Coordinator has a Transfer Capability Methodology but failed to address one or two of the items listed in Requirement R1 Part 1.4”; “The Planning Coordinator has a Transfer Capability Methodology but failed to incorporate one of the Requirement R1 Parts 1.1, 1.2, 1.3, and 1.5 OR The Planning Coordinator has a Transfer Capability Methodology but failed to address three of the items listed in Requirement R1 Part 1.4.” A High VSL was assigned for failure to address four of the items listed in Requirement R1 Part 1.4 – and a Severe was assigned for failure to address more than four of the items listed in Requirement R1 Part 1.4.The SDT has modified the VSL for Requirement R3 to eliminate the gap.				
10	Western Electricity Coordinating Council	Louise McCarren	Negative	We agree with the proposed VRFs, but there is a problem with the VSL for R1. As proposed there is overlap between the Lower and Moderate VSL for R1. The Lower VSL reads: The Planning Coordinator has a PTCMD but failed to address ONE OR TWO of the items listed in Requirement R1, Part 1.1. The second part of the Moderate VSL reads: The Planning Coordinator has a PTCMD but failed to address TWO or more of the items listed in Requirement 1, Part 1.1 If the PC has a PTCMD but failed to address TWO of the items listed in Requirement R1, Part 1.1, they would meet the language of both the Lower and the Moderate VSL. We suggest you change the second part of the Moderate VSL to read The Planning Coordinator has a PTCMD but failed to address THREE or more of the items listed in Requirement 1, Part 1.1
Response: Requirement R1 has been extensively revised; the SDT has modified the VSLs to be consistent with the new Requirement R1 and your comments. The SDT has modified the Requirement R1 Lower and Moderate VSLs to “The Planning Coordinator has a Transfer Capability Methodology but failed to address one or two of the items listed in Requirement R1 Part 1.4”; “The Planning Coordinator has a Transfer Capability Methodology but failed to incorporate one of the Requirement R1 Parts 1.1, 1.2, 1.3, and 1.5 OR The Planning Coordinator has a Transfer Capability Methodology but failed to address three of the items listed in Requirement R1 Part 1.4.” A High VSL was assigned for failure to address four of the items listed in Requirement R1 Part 1.4 – and a Severe was assigned for failure to address more than four of the items listed in Requirement R1 Part 1.4. The SDT feels that the gradations are now appropriate for each sub-part.				

<table>
<tr><th>Segment</th><th>Company</th><th>Balloter</th><th>Opinion</th><th>Comments</th></tr>
<tr><td>10</td><td>ReliabilityFirst Corporation</td><td>Anthony E Jablonski</td><td>Negative</td><td>ReliabilityFirst generally agrees with the VRFs. ReliabilityFirst voted negative on this poll due to the VSL designations as listed below:
1. R1 – if the PC failed to address two of the items listed in Requirement R1, Part 1.1, they would fall under both the Moderate and High VSL designation.
2. R2 - the designation of number of days is not inclusive. For example, where does an entity fall if they are 30 days late? The Moderate VSL states “not more than 40 calendar days” and the High VSL states “more than 40 calendar days”. If an entity is 40 calendar days late where do they fall (Moderate or High)?
3. R3 - Same type of comment for R2
4. R4 – Requirement R4 has a time requirement within it (at least once each calendar year) which is not stated within the VSL
5. R5 – Same type of comment for R2. Also, the High VLS is open ended (“more than 70 calendar days after their verification and recalculation”). For example, if an entity was either 71 calendar days or 500 calendar days late, they would still fall under the High VSL.</td></tr>
<tr><td colspan="5">Response: Requirement R1 has been extensively revised; the SDT has modified the VSLs to be consistent with the new Requirement R1 and your comments. The SDT has modified the Requirement R1 Lower and Moderate VSLs to “The Planning Coordinator has a Transfer Capability Methodology but failed to address one or two of the items listed in Requirement R1 Part 1.4”; “The Planning Coordinator has a Transfer Capability Methodology but failed to incorporate one of the Requirement R1 Parts 1.1, 1.2, 1.3, and 1.5 OR The Planning Coordinator has a Transfer Capability Methodology but failed to address three of the items listed in Requirement R1 Part 1.4.” A High VSL was assigned for failure to address four of the items listed in Requirement R1 Part 1.4 – and a Severe was assigned for failure to address more than four of the items listed in Requirement R1 Part 1.4.The SDT feels that the gradations are now appropriate for each sub-part.
Regarding your comment concerning R2, using your example, an entity that is 30 days late would be in the lower VSL while and entity that is 40 days late would be in the moderate VSL.
Regarding your comment concerning R3 and R5 the SDT believes that the time periods used in the VSLs are clear and do not require further modification.
The SDT agrees with your comment concerning R4 and has modified the VSL to address the “once each calendar year” issue.</td></tr>
<tr><td>1</td><td>Beaches Energy Services</td><td>Joseph S. Stonecipher</td><td>Negative</td><td>(See my comments on the associated Comment Form.)</td></tr>
<tr><td colspan="5">Response: Please refer to responses on the “Consideration of Comments on Modifications to FAC-012 and FAC-013 for Order 729 Draft FAC-013-2 Standard — Project 2010-10”.</td></tr>
<tr><td>1</td><td>Idaho Power Company</td><td>Ronald D. Schellberg</td><td>Negative</td><td>PTCs are not needed.</td></tr>
<tr><td colspan="5">Response: The SDT agrees and has dropped the term. The standard’s emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values. The industry does not support calculation of ATC beyond the operating horizon. The SDT believes there is a reliability related need for the transfer capability assessment to be conducted.</td></tr>
</table>

Segment	Company	Balloter	Opinion	Comments
1	Keys Energy Services	Stan T. Rzad	Negative	It is unclear whether PTC is intended to be analogous with a total transfer capability or an available transfer capability for the long term. Without that clarity, there will be inconsistency on what PTC means to difference PCs. It is important to the value of the standard and to gain consistency to clarify this and to enable those entities who receive the information to understand both the allegorical total and available transfer capabilities. Please see FMPA's comments submitted through the formal process for more detail.
Response: The PTC definition has been deleted based on industry comments and the concept of a transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values.				
1	Lake Worth Utilities	Walt Gill	Negative	It is unclear whether PTC is intended to be analogous with a total transfer capability or an available transfer capability for the long term. Without that clarity, there will be inconsistency on what PTC means to difference PCs. It is important to the value of the standard and to gain consistency to clarify this and to enable those entities who receive the information to understand both the allegorical total and available transfer capabilities. Please see FMPA's comments submitted through the formal process for more detail.
Response: The PTC definition has been deleted based on industry comments and the concept of a transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values.				
1	Platte River Power Authority	John C. Collins	Negative	Much confusion between "Transfer Capabilities" and "SOLs" was introduced in the beginning. NERC planned to reduce this confusion by retiring FAC-012 and -013 along with implementation of the new MOD standards. The proposed FAC-013-2 fuels more confusion and is not necessary. We have FAC-010-2.1 that addresses the SOL methodology to be used by those calculating transfer capabilities in the Planning Horizon.
Response: The PTC definition has been deleted based on industry comments and the concept of a transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values nor defining SOL's.				
2	Independent Electricity System Operator	Kim Warren	Negative	We do not agree with the need for the two new definitions, hence we do not agree with the requirements and the VRFs and VSLs.
Response: The two new definitions for PTC and PTCMD have been removed from the standard in response to industry comments. The SDT has revised the				

Segment	Company	Balloter	Opinion	Comments
Requirements and the associated VSL.				
3	City of Green Cove Springs	Gregg R Griffin	Negative	It is unclear whether PTC is intended to be analogous with a total transfer capability or an available transfer capability for the long term. Without that clarity, there will be inconsistency on what PTC means to difference PCs. It is important to the value of the standard and to gain consistency to clarify this and to enable those entities who receive the information to understand both the allegorical total and available transfer capabilities. Please see FMPA's comments submitted through the formal process for more detail.
Response: The PTC definition has been deleted based on industry comments and the concept of a transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values.				
3	Southern California Edison Co.	David Schiada	Negative	The proposed FAC-013-2 requires the Planning Coordinator to develop and document a Planning Transfer Capability Methodology Document (PTCMD), to issue a PTCMD to identified entities, to respond to technical questions regarding the PTCMD, and to verify or recalculate Planning Transfer Capabilities (PTCs) at least once a year. SCE has reviewed FAC-013-2 and generally agrees that the requirements included in the standard are appropriate for the calculation of PTCs. However, confusion exists regarding the need to calculate PTCs. Other NERC standards, such as FAC-010 and FAC-014, require the Planning Coordinator to have a documented methodology and to follow that methodology in calculating its System Operating Limits (SOLs). The proposed FAC-013-2 does answer SCE's questions about how calculating PTCs differs from calculating Total Transfer Capability and/or SOLs. In its responses to comments from the last posting of the standard, the drafting team indicated that there was no relationship between the FAC-010/FAC-14 and FAC-013. The drafting team indicated that FAC-010/FAC-14 deal with calculation and communication of SOLs, while FAC-013 only requires calculation of PTCs according to the Planning Coordinator's PTCMD, which is based on the PC's criteria. The drafting team asserted that PTCs may be calculated between areas where no SOL is established. However, this response does not clear up the confusion related to the difference between a PTC and an SOL. Because of this confusion, SCE believes that additional clarification in FAC-013-2 is required.
Response: The PTC definition has been deleted based on industry comments and the concept of a transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The standard's				

Segment	Company	Balloter	Opinion	Comments
emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values nor defining SOL's.				
4	Florida Municipal Power Agency	Frank Gaffney	Negative	It is unclear whether PTC is intended to be analogous with a total transfer capability or an available transfer capability for the long term. Without that clarity, there will be inconsistency on what PTC means to difference PCs. It is important to the value of the standard and to gain consistency to clarify this and to enable those entities who receive the information to understand both the allegorical total and available transfer capabilities. Please see FMPA's comments submitted through the formal process for more detail.
Response: The PTC definition has been deleted based on industry comments and the concept of a transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values.				
5	Florida Municipal Power Agency	David Schumann	Negative	It is unclear whether PTC is intended to be analogous with a total transfer capability or an available transfer capability for the long term. Without that clarity, there will be inconsistency on what PTC means to difference PCs. It is important to the value of the standard and to gain consistency to clarify this and to enable those entities who receive the information to understand both the allegorical total and available transfer capabilities. Please see FMPA's comments submitted through the formal process for more detail.
Response: The PTC definition has been deleted based on industry comments and the concept of a transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values.				
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	It is unclear whether PTC is intended to be analogous with a total transfer capability or an available transfer capability for the long term. Without that clarity, there will be inconsistency on what PTC means to difference PCs. It is important to the value of the standard and to gain consistency to clarify this and to enable those entities who receive the information to understand both the allegorical total and available transfer capabilities. Please see FMPA's comments submitted through the formal process for more detail.
Response: The PTC definition has been deleted based on industry comments and the concept of a transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values.				

Segment	Company	Balloter	Opinion	Comments
5	Xcel Energy, Inc.	Liam Noailles	Negative	Much confusion exists regarding the practical distinction between “Transfer Capability”, “Total Transfer Capability” and “System Operating Limit” in general and, in particular, regarding their significance as applied within the Western Interconnection. NERC planned to reduce this confusion by retiring FAC-012 and FAC-013 concurrent with the implementation of the MOD-028/029/030 standards addressing the transfer capability methodologies. The proposed FAC-013-2 fuels more confusion and is not necessary. We have FAC-010 that addresses the SOL methodology which, together with MOD-028/029/030 for transfer capability methodology, comprises a fully adequate suite of methodologies for calculating Transfer Capabilities in the Planning Horizon.
Response: The PTC definition has been deleted based on industry comments and the concept of a transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The standard’s emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values nor defining SOL’s. The SDT believes there is a reliability related need for the transfer capability assessment to be conducted. The SDT does not believe the standards referenced adequately cover the need at this time.				
6	Platte River Power Authority	Carol Ballantine	Negative	Much confusion between “Transfer Capabilities” and “SOLs” was introduced in the beginning. NERC planned to reduce this confusion by retiring FAC-012 and -013 along with implementation of the new MOD standards. The proposed FAC-013-2 fuels more confusion and is not necessary. We have FAC-010-2.1 that addresses the SOL methodology to be used by those calculating transfer capabilities in the Planning Horizon.
Response: The PTC definition has been deleted based on industry comments and the concept of a transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The standard’s emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values nor defining SOL’s.				
1	Orlando Utilities Commission	Brad Chase	Negative	This standard requires that you document how you calculate ATC in the planning horizon if you use it -The standard (arguably) doesn’t require you to calculate ATC in the planning horizon if you don’t use it *However it would probably be safer to calculate one then argue you don’t use it. -The standard set’s no performance criteria, negative ATC is as good as positive ATC. *However if you do calculate a negative value, that becomes available for FERC to review and while it may not be strictly a standard violation, FERC could argue that you “aren’t meeting your firm obligations”
Response: The standard does not require the calculation of ATC in the planning horizon. The PTC definition has been deleted based on industry comments				

Segment	Company	Balloter	Opinion	Comments
and the concept of a transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values.				
6	Florida Municipal Power Pool	Thomas E Washburn	Negative	Unofficial Comment Form for Project 2010-10 — Modifications to FAC-012 and FAC-013 for Order 729 — Draft FAC-013-2 Standard Please DO NOT use this form. Please use the electronic comment form located at the link below to submit comments on the proposed SAR and modifications proposed FAC-013-2 — Planning Transfer Capability. Comments must be submitted by November 3, 2010. If you have questions please contact Darrel Richardson at Darrel.richardson@nerc.net or by telephone at 609-613-1848. https://www.nerc.net/nercsurvey/Survey.aspx?s=e90004c891d2475ea8f1f74a35d5e2ba Background Information: The SAR for Project 2010-10 – Modifications to FAC-012 and FAC-013 for Order 729 proposes modifications to the following standards: • FAC-012-1 — Transfer Capability Methodology • FAC-013-1 — Establish and Communicate Transfer Capabilities In Order 729, FERC ruled that the ATC standards developed in Project 2006-07 did not completely address the topics covered in FAC-012 and -013 and did not fully address the associated directives from Order 693. Accordingly, FERC denied the portions of the implementation plan that would have retired these standards, and instead directed NERC to use the standards development process to make changes to the FAC standards and file those changes with FERC no later than 60 days prior to the effective date of the standards, which is April 1, 2011 (requiring the proposed changes to be filed on or before January 31, 2011). NERC has an obligation to address FERC's directives. It is the intent to identify all the applicable FERC directives and incorporate them in the draft standard. A second draft of the proposed standard has been developed that attempts to address the applicable FERC directives as well as address concerns raised by the industry during the first posting. Please review the proposed draft standard in its entirety and answer the following questions by using the electronic comment form. You do not have to answer all questions. Enter all comments in Simple Text Format. 1. The SDT has modified the definition of Planning Transfer Capability (PTC). The definition now reads "The Transfer Capability that is calculated for the planning period beyond 13 months." Do you agree that the revised definition provides additional clarity as to the time period for the calculations? 0 Yes 1 No Comments: It is unclear whether PTC is allegorical to TTC or to ATC. The term

Segment	Company	Balloter	Opinion	Comments
				should be modified to clarify whether PTC is the total or the incremental available. Without this clarity, on PC might calculate a total whereas its neighboring PC calculate an incremental available value and the numbers will be dramatically different causing confusion. Also, it leaves the values of PTC open to interpretation. FMPA recommends that PTC be calculated as the total; however, the PC should also report the TRM, CBM and existing long term firm commitments assumed so that entities understand that the total may not all be available (e.g., in the PTCMD). 2. The SDT has modified the definition of Planning Transfer Capability Implementation Document (PTCID) so that it is now called Planning Transfer Capability Methodology Document (PTCMD). The definition now reads "A document that describes the process for calculating Planning Transfer Capability (PTC)." Do you agree that the revised definition provides additional clarity as to the purpose of the document? 0 Yes 1 No Comments: Mention should be made of the assumptions as well as the process / method 3. The SDT has modified the Requirements to include data and modeling information as well as provide for additional clarity regarding the intent of the Requirement. Do you agree that the revised Requirements accomplish this goal? 0 Yes 1 No Comments: A new sub-requirement should be added that requires listing of existing long term firm point to point transmission service that would consume PTC (assuming PTC is a "total" and not an "available" number). 4. The SDT has modified the VRFs to better align with the risk associated with the Requirements. Do you agree that the VRFs are now more consistent with regards to the risk associated with the Requirements? 1 Yes 0 No Comments: 5. The SDT has modified the Measures to better align with the Requirements. Do

Segment	Company	Balloter	Opinion	Comments
				you agree that the Measures are now more consistent with the Requirements? 0 Yes 1 No Comments: M3 and M4 are simply restatements of the requirements. FMPA suggests adding "such as (examples of evidence)" statements similar to those provided in M1, M2 and M5. 6. The SDT has modified the VSLs to better align with the severity of non-compliance associated with the Requirements. Do you agree that the VSLs are now more consistent with regards to the severity of non-compliance associated with the Requirements? 1 Yes 0 No Comments: 7. When reviewing the mapping document posted with the proposed FAC-013-2 standard, do you believe that the proposed standard (considering only the requirements assigned to the Planning Coordinator) will be lead to an improvement in reliability when compared to the standards it proposes to replace? 1 Yes 0 No
Response: The PTC definition has been deleted based on industry comments and the concept of a transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values. Regarding comments 2 through 7 please refer to the response provided in the formal comment form.				
1	Seattle City Light	Pawel Krupa	Negative	The scope of the standard is unclear because it does not specify which entities, lines or paths it applies to. Further, Seattle believes this standard should specifically apply to a Planning Authority required by its Regional Reliability Organization to establish interregional and intra-regional Transfer Capabilities, and thus is duplicative of other existing NERC standards.
Response: The purpose of standard is to require Planning Coordinators to have a method for analysis of the ability to transfer energy (beyond 13 months) to identify potential future weaknesses and limiting facilities. The standard allows each Planning Coordinator to determine the method (transfer level, paths, contingencies,…) that best allows them to identify potential future weaknesses and limiting facilities according to their understanding of the needs of the system. The commission stated in Order 693 paragraph 790 "The Commission does not believe that the regional reliability organization should be able to decide the type of entity to which this Reliability Standard applies. …" and the SDT agrees.				

Segment	Company	Balloter	Opinion	Comments
The SDT believes there is a reliability related need for the transfer capability assessment to be conducted. The SDT does not believe the TPL standards adequately cover the need at this time.				
1	Tri-State G & T Association, Inc.	Keith V. Carman	Negative	Tri-State does not agree with the requirement to recalculate PTC values for all paths. A notation of changing values is sufficient.
Response: The purpose of standard is to require Planning Coordinators to have a method for analysis of the ability to transfer energy (beyond 13 months) to identify potential future weaknesses and limiting facilities. The standard allows each Planning Coordinator to determine the method (transfer level, paths, contingencies,…) that best allows them to identify potential future weaknesses and limiting facilities according to their understanding of the needs of the system. The revised standard does not require calculation of any PTC values.				
3	Tri-State G & T Association, Inc.	Janelle Marriott	Negative	We do not agree with the requirement to recalculate PTC values for all paths. A notation of changing values is sufficient
Response: The purpose of standard is to require Planning Coordinators to have a method for analysis of the ability to transfer energy (beyond 13 months) to identify potential future weaknesses and limiting facilities. The standard allows each Planning Coordinator to determine the method (transfer level, paths, contingencies,…) that best allows them to identify potential future weaknesses and limiting facilities according to their understanding of the needs of the system. The revised standard does not require calculation of any PTC values.				
2	Electric Reliability Council of Texas, Inc.	Chuck B Manning	Negative	ERCOT ISO has joined in the submission of the IRC SRC comments and submitted independent comments through the online survey. Please see online survey submissions for details.
Response: Thank you				
3	APS	Steven Norris	Negative	R1.4 requires that assumptions and criteria to calculate PTCs be as, or more limiting than the assumptions and criteria used in operating horizon. This is a vague requirement. The standard needs to provide specific guidelines on how to achieve this or R1.4 should be removed.
Response: The statement has been revised to require (under new Requirement R1 Part 1.3) that the assumptions and criteria used to perform the assessment are consistent with the Planning Coordinator's planning practices because the purpose of the standard is to support planning for reliable system operation in the planning horizon.				
5	Avista Corp.	Edward F. Groce	Negative	Requirement R1.4 disregards the differences between planning and operations. R1.4 requires that the Methodology Document" includes: "A statement that the assumptions and criteria used to calculate PTCs are as, or more, limiting than the assumptions and criteria used in the operating horizon." Since operating assumptions represent short term current operating conditions (such as planned short term outages and low hydro), it is not reasonable to have a requirement that "assumptions and criteria used to calculate PTCs are as, or more, limiting than the assumptions and criteria used in the operating horizon".

Segment	Company	Balloter	Opinion	Comments
Response: The statement has been revised to require (under new Requirement R1 Part 1.3) that the assumptions and criteria used to perform the assessment are consistent with the Planning Coordinator's planning practices because the purpose of the standard is to support planning for reliable system operation in the planning horizon.				
5	MidAmerican Energy Co.	Christopher Schneider	Negative	MidAmerican supports the Midwest Independent System Operator and Midwest Reliability Organization NERC Standards Review Subcommittee positions that several issues in this proposed standard need to be addressed. While MidAmerican understands the need to ensure that entities do not discourage transmission schedules through different assumptions in planning and operation horizons, the fundamental issue with the proposed Planning Transfer Capability Methodology standard is that it continues to confuse operational and planning case assumptions in R1.1 (last bullet) and R1.4. Both items should be deleted. Fundamentally a future planning case is a prediction and model of reality which inherently assumes conditions that may or may not be more limiting when reality and the actual operating horizon is reached.
Response: The concept of transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values. The SDT has extensively revised Requirement R1 based on industry stakeholders' comments.				

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments on Initial Ballot — FAC Order 729 (Project 2010-10)

Date of Initial Ballot: October 20 – November 3, 2010

Summary Consideration: An initial ballot was conducted from October 20-November 3 and achieved a quorum of 89% and a weighted segment approval of 40%. There were many comments submitted with both affirmative and negative ballots.

The majority of the negative comments questioned the relationship between Planning Transfer Capability (PTC), Available Transfer Capability (ATC), Total Transfer Capability (TTC) and System Operating Limits (SOLs). They indicated a need for clarity as to whether PTC was intended to be analogous with TTC or an ATC for the long term and if PTC was simultaneous or non-simultaneous. The PTC definition was deleted based on industry comments. The standard was revised and no longer focuses on developing PTCs, the focus is on assessing transfer capability in the Near-Term Planning Horizon. This clarification should avoid confusion and draw a distinction from the calculations of ATC/AFC/TTC performed in the operating horizon. The standard's purpose was revised to clarify that the standard focuses on assessment of future reliability and facilities that may be impacted by changes in transfers, not specific transfer capability values. The revised standard allows the Planning Coordinator to determine the Transfer Capability assessment methodology and PTC can be simultaneous or non-simultaneous.

Several negative comments indicated that Requirement R1 Part 1.4 was vague and needed additional clarity. The SDT revised this to require (under new Requirement R1 Part 1.3) that the assumptions and criteria used to perform the assessment be consistent with the Planning Coordinator's planning practices because the purpose of the standard is to support planning for reliable system operation in the planning horizon.

Many of the negative comments indicated that the scope of the standard was unclear because it did not specify which entities, lines or paths it applies to. The SDT revised the purpose of the standard to support Planning Coordinators having a method for analysis of the ability to transfer energy (beyond 13 months) to identify potential future weaknesses and limiting facilities. The standard allows each Planning Coordinator to determine the method (transfer level, paths, contingencies,…) that best allows them to identify potential future weaknesses and limiting facilities according to their understanding of the needs of the system.

Some of the negative comments indicated a need for a clearer rationale for having yet another transfer capability value and indicated that SOLs and IROLs already lead to enough confusion. The comments indicated that SOL studies were adequate to define transfer capabilities. The revised standard clearly requires a transfer capability assessment for one year in the Near-Term Planning Horizon. This clarification should avoid confusion and draw a distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The standard's revised emphasis is on a transfer capability assessment of future reliability and facilities that may be impacted by changes in transfers, not specific transfer capability values nor defining SOLs. The SDT believes there is a reliability related need for this assessment to be conducted.

A few of the negative comments indicated that the additional requirements included in the new FAC-013-2 standard when compared to the FAC-012-1 did not add much value in terms of increased reliability. In addition, they indicated that Requirement R1, Part 1.4 (A statement that the assumptions and criteria used to calculate PTCs are as, or more, limiting than the assumptions and criteria used in the operating horizon) was of questionable merit and that each Planning Coordinator should decide what criteria and assumptions are used in the planning horizon vs. the operating horizon without a requirement that the planning horizon is always as, or more, limiting. This draft standard (FAC-013-2) merges the planning requirements in FAC-012-1 and FAC-013-1. The revised standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers. The SDT believes there is a reliability related need for this assessment to be conducted. The SDT does not believe the TPL standards adequately cover the need at this time. Coordination of planning assessments is important to effective planning for future reliable system performance and meets a reliability related need in accordance with the results-based philosophy. The SDT agreed with the comment concerning Requirement R1 Part 1.4 (now Requirement R1, Part 1.3) and modified the standard to require that the assumptions and criteria used to perform the assessment are consistent with the Planning Coordinator's planning practices.

A couple of the negative comments indicated that the Planning Transfer Capability idea should be retired since it does not have any benefits for BES reliability, and would cause additional burden and confusion for Planning Coordinators The revised standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers. The SDT believes there is a reliability related need for this assessment to be conducted and the SDT did not believe the TPL standards adequately cover the need at this time.

If you feel that the drafting team overlooked your comments, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Herb Schrayshuen, at 609-452-8060 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

Voter	Entity	Segment	Vote	Comment
Kirit S. Shah	Ameren Services	1	Negative	(1) While the present standard includes a note in the box indicating that PTC is not a starting point for ATC, our iundersatnding ia that the box would not be included in the final version of the stanadrd. In that case, some one may try to interprete a relation between ATC and PTC. (2) The stanadrd should require PC to develop PTCMD in coordination with TP in their area or have TP develop PTCMD for its area. (3) Would PTC be simultaneous or non-simultaneous or both?
Jennifer Richardson	Ameren Energy Marketing Co.	6		
Response: The language from the text box was revised and moved into the Purpose statement and the text box has been removed. The PTC definition and the definition of TPCMD have been deleted based on industry comments and the concept of a transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The standard does not specify "how" to develop a Transfer Capability methodology – and does not preclude Planning Coordinators from working with other planning entities to develop this methodology. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values. The assessment methodology will be determined by the PC and could be simultaneous or non-simultaneous.				
Gordon Rawlings	BC Transmission Corporation	1	Negative	The SDT is to be commended for their efforts to respond to FERC directions and input from NERC members to combine the standards FAC-012 and FAC-013 in to a single document to cover transfer capabilities in the planning horizon. However, BC Hydro is voting no on this ballot. Based on existing standards BC Hydro has already established transfer capability and SOL methodologies for both the operating and planning horizons under the existing FAC-010 - 013 standards. We believe there is no value added in the creation of new terminology and processes used to calculate Planning Transfer Capabilities. The introduction of this new terminology and possibly new processes to determine PTCs may undermine efforts taken by utilities
Venkataramakrishnan Vinnakota	BC Hydro	2		
Clement Ma	BC Hydro and Power Authority	5		

[1] The appeals process is in the Standard Processes Manual.

Voter	Entity	Segment	Vote	Comment
				to become compliant with the existing standards, introduces duplication and potential for confusion, and ultimately detract from the common goals of increased reliability.
Response: The PTC definition has been deleted based on industry comments and the concept of a transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The standard no longer requires the calculation of Transfer Capabilities. The revised standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers. The SDT believes there is a reliability related need for this assessment to be conducted. The SDT does not believe the TPL standards adequately cover the need at this time.				
Ajay Garg	Hydro One Networks, Inc.	1	Negative	Hydro One is casting a negative vote for the following reasons: 1. Introduction of the term Planning Transfer Capability does not provide any material difference with respect to the term Transfer Capability, which has been defined and adopted for a long period of time. The industry is familiar with this definition, and has a deep and unambiguous understanding of it. The proposed definition for Planning Transfer Capability is redundant and trivial since it still uses the Transfer Capability term within the definition, with additional wording to indicate it is calculated for the planning period only. We believe this distinction can be achieved simply by inserting the phrase "in the planning period" to the term Transfer Capability in the appropriate requirements of the standard. 2. Creating additional definitions requires additional maintenance of the glossary, and may create conflicting understanding for the same terms defined in different jurisdictions and documents (e.g. regional standards, legislation, etc.), and is to be avoided if words in the standards can convey the same intent/meaning.
David L Kiguel	Hydro One Networks, Inc.	3		
Response: The PTC definition has been deleted based on industry comments and the concept of a transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The time period applicable to the assessment has been identified as the Near-Term Transmission Planning Horizon in the body of the requirements. The revised standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values.				
James McMorran	Nevada Power Co.	1	Negative	Negative ballot because PTC's, as described in the draft Standard, are duplicative to SOL's, which are already satisfactorily addressed in FAC-010 and FAC-014. The presence of this proposed Standard will unnecessarily confuse and complicate the overall requirements of the Planning Coordinator.
Response: The PTC definition has been deleted based on industry comments and the concept of a transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The SDT does not believe there is an overlap between the revised draft and the FAC-010 and -014. These deal with identification of SOLs. The revised FAC-013 standard's emphasis is on assessment of future reliability and facilities that may be impacted by				

Voter	Entity	Segment	Vote	Comment
changes in transfers - not specific transfer capability values nor defining SOLs. The standard no longer requires the calculation of Transfer Capabilities.				
Brad Chase	Orlando Utilities Commission	1	Negative	This standard requires that you document how you calculate ATC in the planning horizon if you use it -The standard (arguably) doesn't require you to calculate ATC in the planning horizon if you don't use it *However it would probably be safer to calculate one then argue you don't use it. -The standard set's no performance criteria, negative ATC is as good as positive ATC. *However if you do calculate a negative value, that becomes available for FERC to review and while it may not be strictly a standard violation, FERC could argue that you "aren't meeting your firm obligations"
Response: The standard does not require documenting how you calculate ATC in the planning horizon. The PTC definition has been deleted based on industry comments and the concept of transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The revised standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values.				
John C. Collins	Platte River Power Authority	1	Negative	Much confusion between "Transfer Capabilities" and "SOLs" was introduced in the beginning. NERC planned to reduce this confusion by retiring FAC-012 and -013 along with implementation of the new MOD standards. The proposed FAC-013-2 fuels more confusion and is not necessary. We have FAC-010-2.1 that addresses the SOL methodology to be used by those calculating transfer capabilities in the Planning Horizon.
Brandy A Dunn	Western Area Power Administration	1		
Carol Ballantine	Platte River Power Authority	6		
Response: The PTC definition has been deleted based on industry comments and the concept of transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The revised standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values nor defining SOLs. The standard no longer requires the calculation of Transfer Capabilities.				
Liam Noailles	Xcel Energy, Inc.	5	Negative	Much confusion exists regarding the practical distinction between "Transfer Capability", "Total Transfer Capability" and "System Operating Limit" in general and, in particular, regarding their significance as applied within the Western Interconnection. NERC planned to reduce this confusion by retiring FAC-012 and FAC-013 concurrent with the implementation of the MOD-028/029/030 standards addressing the transfer capability methodologies. The proposed FAC-013-2 fuels more confusion and is not necessary. We have FAC-010 that addresses the SOL methodology which, together with MOD-028/029/030 for transfer capability methodology, comprises a fully adequate suite of methodologies for calculating Transfer Capabilities in the Planning Horizon.
David F. Lemmons	Xcel Energy, Inc.	6		

Voter	Entity	Segment	Vote	Comment
Response: The PTC definition has been deleted based on industry comments and the concept of a transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The revised standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values nor defining SOLs. The standard no longer requires the calculation of Transfer Capabilities. The SDT believes there is a reliability related need for the transfer capability assessment to be conducted. The SDT does not believe the standards referenced adequately cover the need at this time.				
Frank F. Afranji	Portland General Electric Co.	1	Negative	PGE agrees with the WECC position paper that the primary concern identified as being the confusion regarding the need to calculate PTCs. We support the question seeking clarity regarding how calculating PTCs differ from calculating Total Transfer Capability and/or SOLs. Based on the time horizons identified within the MOD standards additional clarification is needed.
Response: The PTC definition has been deleted based on industry comments and the concept of transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The revised standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values nor defining SOL's. The standard no longer requires the calculation of Transfer Capabilities.				
Laurie Williams	Public Service Company of New Mexico	1	Negative	The requirements included in the standard are appropriate for the calculation of PTCs, however, the primary concern is the confusion regarding the need to calculate PTCs. Other NERC standards, FAC-010 and FAC-014, require the Planning Coordinator to have a documented methodology and to follow that methodology in calculating its System Operating Limits (SOLs). Questions seeking clarity regarding how calculating PTCs differ from calculating Total Transfer Capability and/or SOLs have not cleared up the confusion. In their response to comments from the last posting the drafting team indicated that there is no relationship between the FAC-010/FAC-14 and FAC-013. The drafting team indicated that FAC-010/FAC-14 deal with calculation and communication of SOLs while FAC-013 only requires calculation of PTCs according to the Planning Coordinator's PTCMD, which is based on the PC's criteria. For instance, PTCs may be calculated between areas where no SOL is established. This does not clear up the confusion for many entities in the West related to the difference between a PTC and an SOL. Because of this confusion, PNM believes that FAC-013-2 is duplicative of existing NERC standards and is therefore unnecessary.
Response: The PTC definition has been deleted based on industry comments and the concept of a transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The revised standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values nor defining SO's. The standard no longer requires the calculation of Transfer Capabilities.				

Voter	Entity	Segment	Vote	Comment
Catherine Koch	Puget Sound Energy, Inc.	1	Negative	It appears that PTCs are proposed to be determined for all paths and facilities that already require SOLs to be calculated, and we find no exceptions to this in FAC-010. If there are paths and facilities that do not require SOLs, however, that need PTCs, this needs to be explained. The Planning Methodology requirements of FAC-010 for SOLs seem to parallel the FAC-013-2 requirements. If there are requirements in FAC-013-2 that also need to be imposed in the calculation of reliable SOLs, those requirements need to be added to FAC-010-2. Clarification would be helpful to distinguish between SOLs and Transfer Capabilities as the latter typically is based on the former in WECC and additional methodology appears to be redundant.
Response: The PTC definition has been deleted based on industry comments and the concept of a transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values nor defining SOLs. The standard no longer requires the calculation of Transfer Capabilities.				
Tim Kelley	Sacramento Municipal Utility District	1	Negative	Given the proposed definition for Planning Transfer Capability (PTC), SOL and PTC for a 13 month plus planning horizon could be identical methodology/ methodologies. Confusion arises between Planning Transfer Capability and System Operating Limits for the Planning Horizon. Without a clear delineation of terms between SOL & PTC it is difficult to bifurcate the specific standards requirements and exposes entities to violation across Standards. It would be helpful in a decision to cast an Affirmative vote if the drafting team provides a clear description of the differences between an SOL for the Planning Horizon and a Planning Transfer Capability, that demonstrates why this standard is needed.
James Leigh-Kendall		3		
Mike Ramirez		4		
Bethany Wright		**5**		
Response: The PTC definition has been deleted based on industry comments and the concept of a transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values nor defining SOLs. The standard no longer requires the calculation of Transfer Capabilities.				
Dana Cabbell	Southern California Edison Co.	1	Negative	The proposed FAC-013-2 requires the Planning Coordinator to develop and document a Planning Transfer Capability Methodology Document (PTCMD), to issue a PTCMD to identified entities, to respond to technical questions regarding the PTCMD, and to verify or recalculate Planning Transfer Capabilities (PTCs) at least once a year. SCE has reviewed FAC-013-2 and generally agrees that the requirements included in the standard are appropriate for the calculation of PTCs. However, confusion exists regarding the need to calculate PTCs. Other NERC standards, such as FAC-010 and FAC-014, require the Planning Coordinator to have a documented methodology and to follow that methodology in calculating its System
David Schiada	Southern California Edison Co.	3		

Voter	Entity	Segment	Vote	Comment
				Operating Limits (SOLs). The proposed FAC-013-2 does answer SCE's questions about how calculating PTCs differs from calculating Total Transfer Capability and/or SOLs. In its responses to comments from the last posting of the standard, the drafting team indicated that there was no relationship between the FAC-010/FAC-14 and FAC-013. The drafting team indicated that FAC-010/FAC-14 deal with calculation and communication of SOLs, while FAC-013 only requires calculation of PTCs according to the Planning Coordinator's PTCMD, which is based on the PC's criteria. The drafting team asserted that PTCs may be calculated between areas where no SOL is established. However, this response does not clear up the confusion related to the difference between a PTC and an SOL. Because of this confusion, SCE believes that additional clarification in FAC-013-2 is required.
Response: The PTCMD definition and PTC definition have been deleted based on industry comments and the concept of a transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The revised standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values nor defining SOLs. The standard no longer requires the calculation of Transfer Capabilities.				
Gregory Van Pelt	California ISO	2	Negative	We ask the SDT to clearly explain what the difference is between PTCs and SOLs in the planning horizon. Are PTCs different from SOLs in the planning horizon? Additional clarification is required from that previously provided by the SDT to clearly address the unresolved questions for entities in the Western Interconnection still asking the question as to what's the difference between PTCs and SOLs in the planning horizon, and whether FAC-013-2 is duplicative of existing NERC standards. How would the PTCMD methodology in FAC-013-2 differ from the SOL methodology for the planning horizon for FAC-010-2.1 and from the existing requirements in FAC-014 R3 and R5.3?
Response: The PTC and PTCMD definitions have been deleted based on industry comments and the concept of a transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The revised standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values nor defining SOLs. The standard no longer requires the calculation of Transfer Capabilities.				
Kim Warren	Independent Electricity System Operator	2	Negative	We repeat our main objection that is also contained in the comment form for this project. We continue to disagree with the need to define these two new terms. A review of the Comment Report also suggests that the majority of the commenters disagree with the need to define these terms. We are disappointed that the SDT chose to ignore the majority comments. Our previous comments suggested that the term PTC does not provide any material difference than the term Transfer Capability, which has been

Voter	Entity	Segment	Vote	Comment
				defined and adopted for a long period of time. The industry is familiar with this definition, and has a deep and unambiguous understanding that in general term, it is the attainable level of power transfer from one point to another or on a specific transmission path. The proposed definition for PTC is redundant and trivial since it still uses Transfer Capability as a defined term, with additional wording to indicate it is calculated for the planning period only. We believe this distinction can be achieved simply by insetting the phrase "in the planning period" to the term Transfer Capability in the appropriate requirements of the standard. Creating additional definitions require additional maintenance of the glossary, and may create conflicting understanding for the same terms defined in different jurisdiction and documents (e.g. regional standards, legislation, etc.), and is to be avoided if words in the standards can convey the same intent/meaning. Additionally, We concur with the list of elements to be addressed in R1.1, and with the inclusion of R1.2 and R1.5, but have the following comments on R1.3 and R1.4. R1.3 - For clarity we recommend appending " including IROLs." R1.4 should be removed. The appropriate assumptions are determined by the planning assessment personnel. The assumption can be more or less stringent than those applied in the operation horizon depending on the known and expected system conditions. Also, the criteria used in the two horizons can be different. For example, the TPL standards stipulate the contingency and performance requirements for planning assessment but the same set of comprehensive requirements do not currently exist for operation study or SOL/IROL calculations. Some in the industry have made it known that they would apply different contingency/performance criteria to operation assessment and in planning assessment. The industry's rejection to the SAR 2 years ago which proposed changes to FAC-010 and FAC-011 to achieve consistency in the planning and operation criteria provides this evidence.

Response: The PTC and PTCMD definitions have been deleted based on industry comments and the concept of a transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The time period applicable to the assessment has been identified as the Near-Term Transmission Planning Horizon in the body of the requirements. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values. The standard no longer requires the calculation of Transfer Capabilities.
The SDT believes IROLs are included by definition and including again would be redundant.
Requirement R1 Part 1.4. (now Requirement R1 Part 1.3.) is included to address a FERC directive. It has been modified to include the phrase "… consistent with the Planning Coordinator's planning practices."

Voter	Entity	Segment	Vote	Comment
Stan T. Rzad	Keys Energy Services	1	Negative	It is unclear whether PTC is intended to be analogous with a total transfer capability or an available transfer capability for the long term. Without that clarity, there will be inconsistency on what PTC means to difference PCs. It is important to the value of the standard and to gain consistency to clarify this and to enable those entities who receive the information to understand both the allegorical total and available transfer capabilities. Please see FMPA's comments submitted through the formal process for more detail.
Walt Gill	Lake Worth Utilities	1		
Randall McCamish	City of Vero Beach	1		
Frank Gaffney	Florida Municipal Power Agency	4		
Gregg R Griffin	City of Green Cove Springs	3		
Gregory David Woessner	Kissimmee Utility Authority	3		
Richard L. Montgomery	Florida Municipal Power Agency	6		
Response: The PTC definition has been deleted based on industry comments and the concept of a transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The revised standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values. The standard no longer requires the calculation of Transfer Capabilities. Please see response to the FMPA comments.				
David Schumann	Florida Municipal Power Agency	5	Negative	It is unclear whether PTC is intended to be analogous with a total transfer capability or an available transfer capability for the long term. Without that clarity, there will be inconsistency on what PTC means to difference PCs. It is important to the value of the standard and to gain consistency to clarify this and to enable those entities who receive the information to understand both the allegorical total and available transfer capabilities.
Richard Kinas	Orlando Utilities Commission	5		
Thomas W. Richards	Fort Pierce Utilities Authority	4		
Timothy Beyrle	City of New Smyrna Beach Utilities Commission	4		
Paul Shipps	Lakeland Electric	6		

Voter	Entity	Segment	Vote	Comment
Response: The PTC definition has been deleted based on industry comments and the concept of a transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The revised standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values. The standard no longer requires the calculation of Transfer Capabilities.				
Christopher L de Graffenried	Consolidated Edison Co. of New York	1	Negative	1. Clarification is needed for Text box on top of page 3 - Difference between "Available Transfer Capabilities" and "Available Flowgate Capabilities" 2. R1-part 1.1-last bullet - "Reliability margins applied to reflect uncertainty with BES conditions." It sounds as if a reducing factor should be applied to calculated transfer capabilities to account for uncertainty in BES conditions. This is currently not done, nor is it recommended going forward, given the fact the a transmission adequacy assessment such as this one is deterministic in nature. Transfer capability, from a planning perspective, is performed assuming all system elements in service. Alternatively, the System Operating Limits computation is an assessment of specific system conditions projected for the short term horizon (i.e. seasonal). Other types of analysis, such as the LOLE (Loss Of Load Probability) are a different type of assessment based on a probabilistic approach. 3. Is there a particular significance to the fact that we use the term "Limit" when referring to System Operating Limits, while we use the term Capability when referring to Planning Transfer Capabilities?
Peter T Yost	Consolidated Edison Co. of New York	3		
Wilket (Jack) Ng	Consolidated Edison Co. of New York	5		
Nickesha P Carrol	Consolidated Edison Co. of New York	6		
Response: The text box has been removed and the revised standard does not include any references to ATC or AFT. The PTC definition has been deleted based on industry comments and the concept of a transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The revised standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values. The referenced last bullet has been removed from the standard. The standard no longer requires the calculation of Transfer Capabilities.				
Janelle Marriott	Tri-State G & T Association, Inc.	3	Negative	Question 1 - definition of Planning Transfer Capability (PTC) Tri-State finds that sets of TTC values TOs maintain, which are calculated for all posted paths, is sufficient to quantify TTC and ATC both in the operating timeframe and into the planning timeframe. We find creation of an additional term (PTC) unnecessary and think it will be confusing. In particular, there would be no less confusion as to what time frame "PTC" is stated for. It would be sufficient to state when and by how much TTC is expected to change upon completion of some future system modification. There can also be some confusion whether PTC is Planning-timeframe Transfer Capability, comparable to ATC, or Planning-timeframe Total Transfer Capability, comparable to TTC. Question 2 - Planning Transfer Capability Methodology Document (PTCMD)

Voter	Entity	Segment	Vote	Comment
				Changing the term from "ID" (implementation document) to "MD" adds confusion because it differs from the convention used in MOD-001 through MOD-030. 3 yes 4 no comment 5 yes 6 no comment Question 7 - does the proposed standard improve reliability? Proposed ratings used in study work can verify that reliability will be maintained and improved with, say, changes in resource size and locations. Planning-timeframe transfer capability values will most likely be the same as existing Total Transfer Capabilities for any posted path - WECC Paths in particular. The useful information is when and by how much will particular ratings change in the future. Requiring a PTC value for every path may just increase the quantity of information that must be processed to find significant changes. Question 8 - any other comments R1.4 It would be much simpler to say "PTC calculations will use assumptions and criteria comparable to those used for MOD-029 through MOD-030." This standard does not specify any particular timeframe beyond the operating horizon. Presumably, this means the PC would not study any timeframe beyond the expected in-service date of the latest committed generation or transmission projects in the PC's area.
Response: The PTC definition has been deleted based on industry comments and the concept of a transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The use of the term PTCMD has been eliminated. The SDT does not believe there is an overlap between the revised draft and the MOD standards. These deal with calculation of ATC/AFC. The revised FAC-013 standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values. The SDT has modified the standard to require that the assumptions and criteria used to perform the assessment are consistent with the Planning Coordinator's planning practices.				
Donald E. Nelson	Commonwealth of Massachusetts Department of Public Utilities	9	Negative	The term "Planning Transfer Capability" did not need to be a defined term and the RSC saw this as problematic
Response: The PTC definition has been deleted based on industry comments and the concept of a transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon.				

Voter	Entity	Segment	Vote	Comment
Jerome Murray	Oregon Public Utility Commission	9	Negative	The primary concern identified is confusion regarding the need to calculate PTCs. Other NERC standards, FAC-010 and FAC-014, require the Planning Coordinator to have a documented methodology and to follow that methodology in calculating its System Operating Limits (SOLs). Questions seeking clarity regarding how calculating PTCs differ from calculating Total Transfer Capability and/or SOLs have not cleared up the confusion. In their response to comments from the last posting the drafting team indicated that there is no relationship between the FAC-010/FAC-14 and FAC-013. The drafting team indicated that FAC-010/FAC-14 deal with calculation and communication of SOLs while FAC-013 only requires calculation of PTCs according to the Planning Coordinator's PTCMD, which is based on the PC's criteria. For instance, PTCs may be calculated between areas where no SOL is established. This does not clear up the confusion for many entities in the West related to the difference between a PTC and an SOL. Because of this confusion, FAC-013-2 is duplicative of existing NERC standards and is therefore unnecessary.
Response: The PTC and PTCMD definitions have been deleted based on industry comments and the concept of a transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values nor defining SOLs. The standard no longer requires the calculation of Transfer Capabilities. The SDT believes there is a reliability related need for this assessment to be conducted. The SDT does not believe the TPL standards adequately cover the need at this time.				
James D Burley	Midwest Reliability Organization	10	Negative	It is questionable what Planning Transfer Capabilities values are used for in the planning horizon.It is not clear if the planning coordinator will indicate what the PTC values represent (specific transmission service requests,first contingency incremental transfer capability, an off-peak condition,a peak condition,or specific operating condition). It is not clear what an operator would do with PTC values that may not represent the operating horizon. Ignoring the PTC valuew, the standard, in requirement R3 and R2.3, needs clarification such that it removes the administrative burden levied on the Planning Coordinator. This burden does not appear congruent with FERC order 890 which already requires the Planning Coordinators to solicit input from stakeholders plus the standard does not address any criteria as to what would be an appropriate reliability related need.
Response: The PTC definition has been deleted based on industry comments and the concept of a transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The revised standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values. The standard no longer requires the calculation of Transfer Capabilities. The SDT believes there is a reliability related need for this assessment to be conducted. The SDT does not believe the TPL standards				

Voter	Entity	Segment	Vote	Comment
adequately cover the need at this time. Coordination of planning assessments is important to effective planning for future reliable system performance. The NERC Reliability Standards apply to all NERC registered entities. Order 890 processes do not.				
Louise McCarren	Western Electricity Coordinating Council	10	Negative	Despite what on its own merit appears to be appropriate requirements for documenting a methodology, communicating that methodology, responding to technical comments regarding that methodology, and verifying or recalculating Planning Transfer Capabilities in accordance with that documented methodology, we are casting a negative vote on FAC-013-2. We believe there is still significant confusion in the industry regarding the need for FAC-013-2. Many believe that FAC-013-2 is duplicative of the requirements of FAC-010-2 to develop and document a System Operating Limits Methodology for the Planning Horizon and FAC-014-2 to establish and communicate those System Operating Limits for the Planning Horizon in accordance with the Methodology developed for FAC-010-2. In responses to comments from the industry, the Drafting Team replied to a comment from Bonneville Power Administration seeking clarification of the relationship between System Operating Limits (SOLs) and a Planning Transfer Capability by stating that FAC-010/FAC-014 deal with the calculation and communication of SOLs while FAC-013 deals with the calculation of PTCs. This factual statement does not clarify the difference between and SOL and a PTC. It only indicates that the two are different. The FAC-013-2 - Planning Transfer Capability White Paper correctly states that the MOD standards only require for the calculation of available transfer capability in the operating horizon. FAC-014 requires the calculation of SOLs for the planning horizon. This seems to identify limits for transfers on the BES in the planning horizon. Without explaining the difference between and SOL and a PTC, requiring the calculation of a PTC for years 2-5 seems duplicative of the requirement for developing SOLs for the planning horizon. The white paper also indicates that PTC calculations are not intended to supersede nor replace SOLs, stating that the calculations for SOLs are based on specific requirements while the calculation of PTCs are based on a methodology determined by the Planning Coordinator. If the Planning Coordinator determined that their methodology for calculating PTCs would be identical to that identified for calculating SOLs in FAC-14, what would be the difference between these two limits? We believe that the drafting team needs to provide a clear description of the difference between a System Operating Limit for the Panning Horizon and a Planning Transfer Capability that, among other things, is required to respect all

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				applicable System Operating Limits. Many entities in the West believe these to be the same thing. If the drafting team can provide a clear description of the differences between an SOL for the Planning Horizon and a Planning Transfer Capability, that demonstrates why this standard is needed, we would change our vote to affirmative in a subsequent ballot.
Response: The PTC definition has been deleted based on industry comments and the concept of a transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values nor defining SOLs. The standard no longer requires the calculation of Transfer Capabilities. The intent of R1.3. (now R1.2.), regarding applicable SOLs, is to ensure the methodology requires the processes Planning Coordinators use to determine and assess transfer capabilities respects all known SOLs – not the identification of new SOLs. The SDT agrees that In many areas, the requirements of this standard are in concert with existing practices and are already considered good utility practice. Therefore, the new standard codifies these practices.				
Chifong L. Thomas	Pacific Gas and Electric Company	1	Negative	PG&E casted a negative vote for the following reasons: 1. Adding another term, "Planning Transfer Capability" for the planning period is not necessary and can be confusing. It is also not clear where this methodology would be applied if "The calculation of Planning Transfer Capabilities is not meant to be a starting point for calculation of Available Transfer Capabilities or Available Flowgate Capabilities." 2. R1 is overly prescriptive and seems to duplicate FAC-010 (the methodology for SOL in the planning horizon). 3. Requirement R1.4 disregards the differences between planning and operating practices. R1.4 requires that the Methodology Document" includes: "A statement that the assumptions and criteria used to calculate PTCs are as, or more, limiting than the assumptions and criteria used in the operating horizon." Since Planning is to determine future transmission investments, it is usual for planning assumptions to represent average system conditions starting with all facilities in service. Sensitivity cases may be run, but they may not be the ones used to set the PTCs. Since operating conditions typically do not have all facilities in service, and must represent the system as is expected in the near term (for example, a drought condition), which will be different from an "average" condition, it is therefore not reasonable (and may not be possible) to make a statement that the "assumptions and criteria used to calculate PTCs are as, or more, limiting than the assumptions and criteria used in the operating horizon".
Response: The PTC definition has been deleted based on industry comments and the concept of a transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The revised standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values nor defining SOLs. The standard no longer requires the calculation of Transfer Capabilities.				

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Requirement R1 has been modified to remove the list of all PTCs to be calculated and is intended to provide Planning Coordinators sufficient flexibility to document a Transfer Capability Methodology that focuses on assessing transfer capabilities that affect reliability of the BES versus those that do not. Requirement R1 Part 1.4 (now Requirement R1 Part 1.3) has been modified to now read “A statement that the assumptions and criteria used to perform the assessment are consistent with the Planning Coordinator’s planning practices.”				
John Canavan	NorthWestern Energy	1	Negative	R1.2. More guidance is needed to compile a list of Planning Transfer Capabilities (PTC) that need to be calculated. Does it only apply to the paths that are listed in the Western Electricity Coordinating Council (WECC) Path Rating Catalog? These paths are already being studied through Operating Transfer Capability (OTC) studies required by the Northwest Operational Planning Study Group study process (NOPSG), which is an oversight committee that reviews the Pacific Northwest sub region of WECC. Or does it apply to all the transmission lines that comprise the bulk electric system (BES)? R4. When the Planning Coordinator verifies the PTCs calculated for the previous year, what guidelines are used to decide if the criteria or assumptions have changed? Generation dispatch is constantly changing, and system demand is also constantly changing. There could be a maximum MW change that would prompt a new PTC calculation. Does “good engineering judgment” qualify as a method to determine if new PTC calculations are needed?
Response: The PTC definition has been deleted based on industry comments and the concept ofa transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The revised standard’s emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values. The standard no longer requires the calculation of Transfer Capabilities. It applies to Transfer Capabilities in the Near-Term Transmission Planning Horizon based on the criteria for selection of transfers to be assessed contained in the Planning Coordinator’s Transfer Capability Methodology. Requirement R4 has been modified and no longer requires verification of the PTCs calculated for the previous year.				
Keith V. Carman	Tri-State G & T Association, Inc.	1	Negative	Tri-State finds that sets of TTC values TOs maintain, which are calculated for all posted paths, is sufficient to quantify TTC and ATC both in the operating timeframe and into the planning timeframe. We find creation of an additional term (PTC) unnecessary and think it will be confusing. In particular, there would be no less confusion as to what time frame “PTC” is stated for. It would be sufficient to state when and by how much TTC is expected to change upon completion of some future system modification. There can also be some confusion whether PTC is Planning-timeframe Transfer Capability, comparable to ATC, or Planning-timeframe Total Transfer Capability, comparable to TTC. Changing the term from “ID” (implementation document) to “MD” adds confusion because it differs from the convention used in MOD-001 through MOD-030. Proposed ratings used

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				in study work can verify that reliability will be maintained and improved with, say, changes in resource size and locations. Planning-timeframe transfer capability values will most likely be the same as existing Total Transfer Capabilities for any posted path - WECC Paths in particular. The useful information is when and by how much will particular ratings change in the future. Requiring a PTC value for every path may just increase the quantity of information that must be processed to find significant changes. In R1.4 it would be much simpler to say "PTC calculations will use assumptions and criteria comparable to those used for MOD-029 through MOD-030." This standard does not specify any particular timeframe beyond the operating horizon. Presumably, this means the PC would not study any timeframe beyond the expected in-service date of the latest committed generation or transmission projects in the PC's area.
Response: The PTC definition has been deleted based on industry comments and the concept of a transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The revised standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values. The standard no longer requires the calculation of Transfer Capabilities. Requirement R1 has been modified to remove the list of all PTCs to be calculated and is intended to provide Planning Coordinators sufficient flexibility to document a Transfer Capability Methodology that focuses on assessing transfer capabilities that affect reliability of the BES versus those that do not. Requirement R1 Part 1.4 (now Requirement R1 Part 1.3) has been modified to now read "A statement that the assumptions and criteria used to perform the assessment are consistent with the Planning Coordinator's planning practices." The revised standard does include a reference to the "Near-term Planning Horizon" for additional clarity and requires the Planning Coordinator to do an assessment for one year in the Near-term Planning Horizon.				
Jason Shaver	American Transmission Company, LLC	1	Negative	The Planning Transfer Capability idea should be retired since it does not have any benefits for BES reliability, but will cause additional burden and confusion for Planning Coordinators: o Transfer capabilities in the planning horizon are not useful for the reliable planning of the transmission system and/or any expansion plans. The current, approved TPL standards already provide system expansion requirements to assure reliable system performance with regard to firm transfer commitments, but not to limits that may exceed those firm commitments such as those that would be indicated in PTC calculations. Further, it must be noted that there are no TPL standards that require system expansion for maintenance of transfer capabilities above firm transfer commitments. As such, transfer capabilities in the planning horizon provide no additional information that can be used for system planning. o Transfer capabilities calculated 2 to 5 years ahead are not useful to give system operators advance warning or appropriate, applicable operating

Voter	Entity	Segment	Vote	Comment
				limits because operating horizon conditions will be significantly different than those projected during the planning horizon (2 to 5 years previously).
Response: The revised standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers. The SDT believes there is a reliability related need for this assessment to be conducted. The standard no longer requires the calculation of Transfer Capabilities. The SDT does not believe the TPL standards adequately cover the need at this time. The revised standard requires the Planning Coordinator to do a Transfer Capability assessment for one year in the Near-term Planning Horizon.				
Jason L Marshall	Midwest ISO, Inc.	2	Negative	The Planning Transfer Capability idea should be retired since it does not have any benefits for BES reliability, but will cause additional burden and confusion for Planning Coordinators: o Transfer capabilities in the planning horizon are not useful for the reliable planning of the transmission system and/or any expansion plans. The current, approved TPL standards already provide system expansion requirements to assure reliable system performance with regard to firm transfer commitments, but not to limits that may exceed those firm commitments such as those that would be indicated in PTC calculations. Further, it must be noted that there are no TPL standards that require system expansion for maintenance of transfer capabilities above firm transfer commitments. As such, transfer capabilities in the planning horizon provide no additional information that can be used for system planning. o Transfer capabilities calculated 2 to 5 years ahead are not useful to give system operators advance warning or appropriate, applicable operating limits because operating horizon conditions will be significantly different than those projected during the planning horizon (2 to 5 years previously). While we disagree with the need for the standard as a whole, the following comments are offered: o The development of the PTCMD, as described in the standard, creates confusion as to whether the PTCMD is intended to describe: (1) the entity's methodology for continued calculation of ATC for the 2 to 5 year horizon as such values would be calculated in response to specific transmission service requests or (2) the entity's methodology for calculation of FCITC in the 2 to 5 year horizon. More specifically, Requirement R1 requires that, at a minimum, the PTCMD include "a description of the assumptions and criteria used in the calculation of Planning Transfer Capabilities (PTCs) to include at a minimum how each of the following are addressed, or an explanation for any of the following not used in the calculation of PTC...". Included in these

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				required elements, at Part 1.1, are "Reliability margins applied to reflect uncertainty with BES conditions" and, at R1.4, are "A statement that the assumptions and criteria used to calculate PTCs are as, or more, limiting than the assumptions and criteria used in the operating horizon". The inclusion of these elements in the calculation of PTC strongly suggests that the intent of this standard and the PTCMD is to describe an entity's methodology for calculation of ATC values for the Planning Horizon. The requirement to include 'Reliability Margins' in the PTC calculation or to provide a justification for not doing so described in R1.1 strongly suggests that the standard has been drafted with the calculation of ATC values as its primary intent. The concept of reliability margins (Capacity Benefit Margin and Transmission Reserve Margin) was specifically designed for the purposes of calculating ATC and selling transmission service in response to FERC's final rules in Orders 888 and 889. Reliability margins are designed to ensure that transmission service is not sold past the point of where the Bulk Electric System ("BES") will be secure and to ensure that the network transmission customers will have access to generation resources. As well, the requirement set forth in R1.1.4, which requires that 'A statement that the assumptions and criteria used to calculate PTCs are as, or more, limiting than the assumptions and criteria used in the operating horizon' be included in the PTCMD indicates that the assumptions and criteria utilized to calculated ATC values under the MOD standards and PTC values under the draft FAC-013-2 standard should be as similar as possible, which also strongly suggests that the standard has been drafted with the calculation of ATC values as its primary intent. Further, the intent of R1.1.4 is unclear and seems counterintuitive to current practices in that the assumptions in the planning horizon are, by virtue of the uncertainties associated with effects of time, less accurate than the operating horizon. o R3 should be removed from the standard as it is an administrative requirement that is unnecessary, contrary to the results-based standards effort and duplicative of existing statutory requirements. More specifically, R3 mandates a stakeholder process for the PTCMD and the calculation of PTC values generally, which process provides no reliability benefit, but provides a method for entities to dispute or request modification to the calculation of specific PTC values, which exceptions must then be documented in a revised PTCMD. The requirement to respond to all technical comments and/or revise PTCs and the PTCMD would be a significant administrative burden to the Planning Coordinators. Additionally,

Voter	Entity	Segment	Vote	Comment
				it should be noted that the NERC Board of Trustees approved the results-based standards initiative which includes a specific, stated goal to eliminate purely administrative requirements, which R3 is. Finally, FERC Order 890 already contains requirements for transmission planners to have stakeholder process. Accordingly, stakeholders already have a process through which they can address, with Planning Coordinators, issues with values and/or assumptions used in the planning horizon and/or system expansion plans. o Part 2.3 should be either be removed due to its subjective nature or criteria for requesting such data should be added to clarify what entities can request such data, under what circumstances they can do so, and how disputes regarding such requests are to be resolved. More specifically, R3 contains no indication regarding the entity that makes the determination that a functional entity had a reliability-related need to the PTCs. Additionally, there are no dispute resolution provisions to govern disagreements between Planning Coordinators and entities requesting data under R3. Accordingly, the drafting team should either remove R3 from the standard or review the functional entities in the functional model and add the specific entities that should have access to the PTCs.
Response: The revised standard does not require the calculation of Transfer Capabilities. The revised standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers. The SDT believes there is a reliability related need for this assessment to be conducted. The SDT does not believe the TPL standards adequately cover the need at this time. No stakeholder process is mandated, the standard only requires response to written comments from parties that have a reliability related need for the assessment. Coordination of planning assessments is important to effective planning for future reliable system performance and meets a reliability related need in accordance with the results-based philosophy. The NERC Reliability Standards apply to all NERC registered entities. Order 890 processes does not.				
Leonard Rentmeester	Wisconsin Public Service Corp.	5	Negative	The basis for the negative vote is contained in the comments provided by the MRO NSRS
Response: Response to be consistent with that to MRO NSRS.				
Robert D Smith	Arizona Public Service Co.	1	Negative	R1.4 requires that assumptions and criteria to calculate PTCs be as, or more limiting than the assumptions and criteria used in operating horizon. This is a vague requirement. The standard needs to provide specific guidelines on how to achieve this or R1.4 should be removed.
Steven Norris	APS	3		

Voter	Entity	Segment	Vote	Comment
Mel Jensen	APS	5		
Response: The statement has been revised to require (under new Requirement R1 Part 1.3) that the assumptions and criteria used to perform the assessment are consistent with the Planning Coordinator's planning practices because the purpose of the standard is to support planning for reliable system operation in the planning horizon.				
Scott Kinney	Avista Corp.	1	Negative	Requirement R1.4 disregards the differences between planning and operations. R1.4 requires that the Methodology Document" includes: "A statement that the assumptions and criteria used to calculate PTCs are as, or more, limiting than the assumptions and criteria used in the operating horizon." Since operating assumptions represent short term current operating conditions (such as planned short term outages and low hydro), it is not reasonable to have a requirement that "assumptions and criteria used to calculate PTCs are as, or more, limiting than the assumptions and criteria used in the operating horizon".
Edward F. Groce	Avista Corp.	5		
Response: The statement has been revised to require (under new Requirement R1 Part 1.3) that the assumptions and criteria used to perform the assessment are consistent with the Planning Coordinator's planning practices because the purpose of the standard is to support planning for reliable system operation in the planning horizon.				
Justin Thompson	Arizona Public Service Co.	6	Negative	R1.4 requires that assumptions and criteria to calculate PTCs be as, or more limiting than the assumptions and criteria used in operating horizon. This is a vague requirement. The standard needs to provide specific guidelines on how to achieve this or R1.4 should be removed.
Response: The statement has been revised to require (under new Requirement R1 Part 1.3) that the assumptions and criteria used to perform the assessment are consistent with the Planning Coordinator's planning practices because the purpose of the standard is to support planning for reliable system operation in the planning horizon.				
John Bussman	Associated Electric Cooperative, Inc.	1	Affirmative	see comments
Response: Please see response to comments.				
Joseph S. Stonecipher	Beaches Energy Services	1	Negative	(See my comments on the Comment Form.)
Response: Please see response to comments.				

Voter	Entity	Segment	Vote	Comment
Donald S. Watkins	Bonneville Power Administration	1	Negative	Please refer to BPA comments submitted during the formal comment period on 10/26/10
Response: Please see response to comments				
George S. Carruba	East Kentucky Power Coop.	1	Negative	The additional requirements included in the new FAC-013-2 standard when compared to the FAC-012-1 do not add much value in terms of increased reliability. These items require the Planning Coordinator to simply describe in more detail which PTCs have been calculated and how. This will have minimal impact on reliability. Sub-requirement 1.4 (A statement that the assumptions and criteria used to calculate PTCs are as, or more, limiting than the assumptions and criteria used in the operating horizon) is of questionable merit. There may be valid reasons why assumptions and criteria used in the operating horizon may be more limiting than those used in the planning horizon. Each Planning Coordinator should decide what criteria and assumptions are used in the planning horizon vs. the operating horizon without a requirement that the planning horizon is always as, or more, limiting. PTCs are not likely to translate into the operating horizon in any event. This sub requirement has no positive impact on reliability of the BES.
Sally Witt	East Kentucky Power Coop.	3		
Stephen Ricker	East Kentucky Power Coop.	5		
Response: This draft standard merges the planning requirements in FAC-012-1 and FAC-013-1. The revised standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers. The SDT believes there is a reliability related need for this assessment to be conducted. The SDT does not believe the TPL standards adequately cover the need at this time. Requirement R1, Part 1.4 - The SDT agrees and has modified the standard to require that the assumptions and criteria used to perform the assessment are consistent with the Planning Coordinator's planning practices. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers. The SDT believes there is a reliability related need for this assessment to be conducted.				
Ronald D. Schellberg	Idaho Power Company	1	Negative	Do not see the rationale for having yet another transfer capability value. SOLs and IROLs lead to enough confusion. SOL studies are adequate to define transfer capabilities.
Response: The revised standard does not require the calculation of Transfer Capabilities. The concept of transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The revised standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values nor defining SOL's. The SDT believes there is a reliability related need for this assessment to be conducted.				
Ted E Hobson	JEA	1	Negative	Based on the stated purpose of the standard, Requirement R1.2 language should be enhanced for clarity to state: "A list of PTCs to be calculated, which are needed for reliability planning coordination" instead of the existing language "A list of all PTCs to be calculated" to

Voter	Entity	Segment	Vote	Comment
				Concerning R4 language: recommend improving clarity and direction with the following language: “R4. Each planning Coordinator shall verify and, if assumptions or criteria as described in the PTCMD have changed, recalculate its PTCs consistent with its PTCMD for beyond 13 months and representative year(s) of the timeframe through year five (to capture system changes that affect PTC) at least once each calendar year, with no more than 15 months between verifications.” It was unclear about what is meant by “for years two through five” which may be overly excessive for the purpose of this standard.
Response: The revised standard does not require the calculation of Transfer Capabilities – it requires an assessment of Transfer Capability. The standard has been modified to allow for a methodology that results in a more efficient and flexible process of determining or assessing the impacts of transfers on facilities in the Near-Term Transmission Planning Horizon. The SDT agrees that assessments do not need to be performed for each year 2-5 and has revised the standard to require assessment of Transfer Capability for one year in the Near-Term Transmission Planning Horizon.				
W. R. Schoneck	Florida Power & Light Co.	3	Negative	This version is a big improvement over the last version but additional clarification is still needed for an affirmative vote .Since the Purpose of the standard states that Planning Transmission Capabilities are needed for reliable planning of the Bulk Electric System. The PTC forecasts need to be reliability based to be meaningful for planning by determining adequate long term capability to ensure reliable operation in the future. Consistent with the stated purpose, Requirement R1.2 should be changed from “A list of all PTCs to be calculated” to “A list of PTCs to be calculated, which are needed for reliability planning coordination” Additionally, Requirement R4 is unclear about what is meant by “for years two through five” and may be excessive. The requirement should allow for the PTC calculation to be performed on representative year(s) (years two through five) of the near-term planning horizon to capture changes affecting PTC. The requirement can be reworded as follows: “R4. Each planning Coordinator shall verify and, if assumptions or criteria as described in the PTCMD have changed, recalculate its PTCs consistent with its PTCMD for beyond 13 months and representative year(s) of the timeframe through year five (to capture system changes that affect PTC) at least once each calendar year, with no more than 15 months between verifications.”
Response: The Purpose of the standard has been clarified and now states: To ensure that Planning Coordinators have a methodology for, and perform an annual assessment of, the ability to transfer energy (in the Near-Term Transmission Planning Horizon) to identify potential future weaknesses and limiting Facilities that could impact the reliability of the Bulk Electric System (BES).				

Voter	Entity	Segment	Vote	Comment
The revised standard does not require the calculation of Transfer Capabilities – it requires an assessment of Transfer Capability. The standard has been modified to allow for a methodology that results in a more efficient and flexible process of determining or assessing transfer capabilities in the Near-Term Transmission Planning Horizon. The SDT has changed the phrase "A list of all PTCs to be calculated" to provide the "criteria for selection of the transfers to be assessed. The standard no longer requires assessments to be performed for each year 2-5 - the revised standard requires an assessment of one year in the Near-Term Transmission Planning Horizon.				
Ronald L Donahey	Tampa Electric Co.	3	Negative	The Purpose of the standard states that Planning Transmission Capabilities are needed for reliable planning of the Bulk Electric System. The PTC forecasts need to be reliability based to be meaningful for planning by determining adequate long term capability to ensure reliable operation in the future. Consistent with the stated purpose, Requirement R1.2 should be changed from "A list of all PTCs to be calculated" to "A list of PTCs to be calculated, which are needed for reliability planning coordination" Requirement R4 is unclear about what is meant by "for years two through five" and may be excessive. The requirement should allow for the PTC calculation to be performed on representative year(s) (years two through five) of the near-term planning horizon to capture changes affecting PTC. The requirement can be reworded as follows: "R4. Each planning Coordinator shall verify and, if assumptions or criteria as described in the PTCMD have changed, recalculate its PTCs consistent with its PTCMD for beyond 13 months and representative year(s) of the timeframe through year five (to capture system changes that affect PTC) at least once each calendar year, with no more than 15 months between verifications." The VSLs for R1 Lower and Moderate are inconsistent or contain an error. Recommend changing Moderate VSL (second part) to "The Planning Coordinator has a PTCMD but failed to address three or more of the items listed in Requirement R1, Part 1.1. The High and Severe VSLs for R1 should spell out the numerical 2 and 3 as "two" and "three" for consistency. The changes in severity levels for R2, R3, and R5 should be in multiples of 30 days, not in multiples of 10 days, which seems haphazardly chosen and severe for requirements that all have Lower VRFs. Similarly, R4 should be in multiples of 25% rather than 5%, particularly since there should not be a need to calculate very many PTCs because they should only be calculated for reliability enhancement reasons. Finally, the word "notified" in each VSL for R5 should be replaced with "made available to" in order to be consistent with the wording in R5.

Voter	Entity	Segment	Vote	Comment
Response: The Purpose of the standard has been clarified and now states: To ensure that Planning Coordinators have a methodology for, and perform an annual assessment of, the ability to transfer energy (in the Near-Term Transmission Planning Horizon) to identify potential future weaknesses and limiting Facilities that could impact the reliability of the Bulk Electric System (BES). The revised standard does not require the calculation of Transfer Capabilities – it requires an assessment of Transfer Capability. The standard has been modified to allow for a methodology that results in a more efficient and flexible process of determining or assessing transfer capabilities in the Near-Term Transmission Planning Horizon. The SDT has changed the phrase "A list of all PTCs to be calculated" to provide the "criteria for selection of the transfers to be assessed. The standard no longer requires assessments to be performed for each year 2-5 - the revised standard requires an assessment of one year in the Near-Term Transmission Planning Horizon. Requirement R1 has been extensively revised; the SDT has modified the VSLs to be consistent with the new Requirement R1. The SDT has modified the Requirement R1 Lower and Moderate VSLs to "The Planning Coordinator has a Transfer Capability Methodology but failed to address one or two of the items listed in Requirement R1 Part 1.4"; "The Planning Coordinator has a Transfer Capability Methodology but failed to incorporate one of the Requirements R1 Parts 1.1, 1.2, 1.3, and 1.5 OR The Planning Coordinator has a Transfer Capability Methodology but failed to address three of the items listed in Requirement R1 Part 1.4." A new High VSL was added for failure to address four of the items listed in Requirement R1, Part 1.4 – and a new Severe VSL was added for failure to address more than four items. The SDT chose increments for Requirements R2, R3 and R5 with increments that vary depending on the content of the requirement. Requirement R4 in the initial draft of FAC-013-2 has been replaced; the new VSLs for Requirement R4 do not use multiples. The SDT has modified Requirement R5 VSL to address your concern.				
Terry Harbour	MidAmerican Energy Co.	1	Negative	MidAmerican supports the Midwest Independent System Operator and Midwest Reliability Organization NERC Standards Review Subcommittee positions that several issues in this proposed standard need to be addressed. While MidAmerican understands the need to ensure that entities do not discourage transmission schedules through different assumptions in planning and operation horizons, the fundamental issue with the proposed Planning Transfer Capability Methodology standard is that it continues to confuse operational and planning case assumptions in R1.1 (last bullet) and R1.4. Both items should be deleted. Fundamentally a future planning case is a prediction and model of reality which inherently assumes conditions that may or may not be more limiting when reality and the actual operating horizon is reached. Including requirements to provide documentation statements about assumptions are completely inconsistent with the results

Voter	Entity	Segment	Vote	Comment
				based standards approach and should be elimianted in all future standards development.
Christopher Schneider	MidAmerican Energy Co.	5	Negative	MidAmerican supports the Midwest Independent System Operator and Midwest Reliability Organization NERC Standards Review Subcommittee positions that several issues in this proposed standard need to be addressed. While MidAmerican understands the need to ensure that entities do not discourage transmission schedules through different assumptions in planning and operation horizons, the fundamental issue with the proposed Planning Transfer Capability Methodology standard is that it continues to confuse operational and planning case assumptions in R1.1 (last bullet) and R1.4. Both items should be deleted. Fundamentally a future planning case is a prediction and model of reality which inherently assumes conditions that may or may not be more limiting when reality and the actual operating horizon is reached.
Dennis Kimm	MidAmerican Energy Co.	6		
Response: Requirement R1, Part 1.4 - The SDT has modified the standard to require that the assumptions and criteria used to perform the assessment are consistent with the Planning Coordinator's planning practices. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers. The SDT believes there is a reliability related need for this assessment to be conducted.				
Larry Akens	Tennessee Valley Authority	1	Negative	The intent of the standard still lacks clarity. The purpose statement reads: "To ensure that Planning Coordinators calculate Planning Transfer Capabilities using an established method such that those forecasts of Transfer Capabilities are available for the reliable planning of the Bulk Electric System (BES)." Resource Planners within a Planning Coordinator's area need an awareness of Planning Transfer Capability into their area of load responsibility in order to plan for sufficient resources inside the area. There is no requirement in the standard to communicate Transfer Capability to the Resource Planners within the Planning Coordinator's area. The proposed standard does not require any coordination between Planning Coordinators in performing these calculations. Planning Transfer Capability that is calculated outside of a jointly coordinated Planning Coordinator study process will likely produce forecasts of Planning Transfer Capability that are less reflective of planned system capabilities. Under R1.1.1, we believe that "monitored facilities" assumptions and criteria should also be addressed in the PTCMD. We believe that requirement R1.1.3 should be modified to reflect that PTC calculations respect TPL criteria as a basis for PTC calculations, rather than
George T. Ballew	Tennessee Valley Authority	5	Negative	
Marjorie S. Parsons	Tennessee Valley Authority	6		

Voter	Entity	Segment	Vote	Comment
				SOLs. The intent of R1.1.4 is unclear, particularly since the standard excludes calculation of Transfer Capability in the operating horizon (inside 13 months).
Response: The Purpose of the standard has been clarified and now states: To ensure that Planning Coordinators have a methodology for, and perform an annual assessment of, the ability to transfer energy (in the Near-Term Transmission Planning Horizon) to identify potential future weaknesses and limiting Facilities that could impact the reliability of the Bulk Electric System (BES). The revised standard does not require the calculation of Transfer Capabilities – it requires an assessment of Transfer Capability. The SDT believes that Requirement R2 provides the means for Resource Planners within the Planning Coordinator's area to provide input in to and receive data from a Planning Coordinator's processes required as part of this standard. The proposed standard does not preclude a Planning Coordinator from working with its Resource Planners and Transmission Planners or with other Planning Coordinators in developing its Transfer Capability methodology. The Requirements in R2, R3 and R5 of sharing methodology and results adequately addresses coordination between Planning Coordinators. Monitored facilities criteria have been added to Requirement R1 Part 1.1. (now Requirement R1 Part 1.4). Requirement R1 Part 1.4. (now Requirement R1 Part 1.3) is included to address a FERC directive. It has been modified to include the phrase "… consistent with the Planning Coordinator's planning practices."				
John Tolo	Tucson Electric Power Co.	1	Negative	Request clarification of the process to determine the various interchange schedules in the base cases that would be needed to calculate PTCs. Not clear if the process for calculating PTCs be the same as that which is used for the Operating Horizon. concern that the requirement to calculate PTCs, in the absence of clear procedures that take future planning uncertainty into account, will be unduly burdensome, while the value will likely be of little value relative to the transmission planning staffing resource impact.
Response: The revised standard does not require the calculation of Transfer Capabilities – it requires an assessment of Transfer Capability. Requirement R1 has been modified to remove the list of all PTC's to be calculated. The revised requirement is intended to provide Planning Coordinators sufficient flexibility to document a Transfer Capability Methodology that focuses on assessing transfer capabilities that affect reliability of the BES versus those that do not. Requirement R1 Part 1.4 (now Requirement R1 Part 1.3) has been modified to now read "A statement that the assumptions and criteria used to perform the assessment are consistent with the Planning Coordinator's planning practices."				
Jonathan Appelbaum	United Illuminating Co.	1	Negative	Comment form submitted.
Response: Please see response to comments.				

Voter	Entity	Segment	Vote	Comment
Chuck B Manning	Electric Reliability Council of Texas, Inc.	2	Negative	ERCOT ISO has joined in the submission of the IRC SRC comments and submitted independent comments through the online survey. Please see online survey submissions for details.
Response: Please see response to comments.				
Francis J. Halpin	Bonneville Power Administration	5	Affirmative	Please refer to BPA comments submitted during the formal comment period on 10/26/10
Rebecca Berdahl	Bonneville Power Administration	3	Negative	
Response: Please see response to comments.				
Charles A. Freibert	Louisville Gas and Electric Co.	3	Negative	LG&E and KU Energy support the comments submitted by the Midwest ISO.
Charlie Martin	Louisville Gas and Electric Co.	5		
Daryn Barker	Louisville Gas and Electric Co.	6		
Response: See responses to Midwest ISO comments.				
Michael Ibold	Xcel Energy, Inc.	3	Negative	See transmission comments.
Response: See responses to transmission comments.				
Pawel Krupa	Seattle City Light	1	Negative	The scope of the standard is unclear because it does not specify which entities, lines or paths it applies to. Further, Seattle believes this standard should specifically apply to a Planning Authority required by its Regional Reliability Organization to establish interregional and intra-regional Transfer Capabilities, and thus is duplicative of other existing NERC standards.
Hao Li	Seattle City Light	4		
Dana Wheelock	Seattle City Light	3		
Michael J. Haynes	Seattle City Light	5		
Dennis Sismaet	Seattle City Light	6		

Voter	Entity	Segment	Vote	Comment
Response: The Purpose of the standard has been clarified and now states: To ensure that Planning Coordinators have a methodology for, and perform an annual assessment of, the ability to transfer energy (in the Near-Term Transmission Planning Horizon) to identify potential future weaknesses and limiting Facilities that could impact the reliability of the Bulk Electric System (BES). The revised standard does not require the calculation of Transfer Capabilities – it requires an assessment of Transfer Capability. The standard allows each Planning Coordinator to determine the method (transfer level, paths, contingencies,…) that best allows them to identify potential future weaknesses and limiting facilities according to their understanding of the needs of the system.				
James A Maenner		8	Negative	The overall purpose of this standard is not clear.
Response: The Purpose of the standard has been clarified and now states: To ensure that Planning Coordinators have a methodology for, and perform an annual assessment of, the ability to transfer energy (in the Near-Term Transmission Planning Horizon) to identify potential future weaknesses and limiting Facilities that could impact the reliability of the Bulk Electric System (BES). The revised standard does not require the calculation of Transfer Capabilities – it requires an assessment of Transfer Capability. The standard allows each Planning Coordinator to determine the method (transfer level, paths, contingencies,…) that best allows them to identify potential future weaknesses and limiting facilities according to their understanding of the needs of the system. The concept of a transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon.				
Anthony E Jablonski	ReliabilityFirst Corporation	10	Affirmative	Even though ReliabilityFirst voted affirmative, we have a few comments for the SDT to consider. They include: 1. The Time Horizons are not consistent with the Criteria for Time Horizons as stated in the NERC Time_Horizons.pdf resource document. To be consistent the Time Horizons should include one of the following: a. Long-term Planning - a planning horizon of one year or longer. b. Operations Planning - operating and resource plans from day-ahead up to and including seasonal. c. Same-day Operations - routine actions required within the timeframe of a day, but not real-time. d. Real-time Operations - actions required within one hour or less to preserve the reliability of the bulk electric system. e. Operations Assessment - follow-up evaluations and reporting of real time operations. 2. The bullet point under Part 1.1 should be renumbered to Part 1.1.1, 1.1.2, etc. Bullet points are generally considered “OR” statements in NERC Standards. Based on the language in Part 1.1, I believe these all these bullets must be addressed and therefore these are “AND” statements.

Voter	Entity	Segment	Vote	Comment
Response: The SDT thanks you for your support. The SDT has made significant clarifying changes to the draft requirements based on comments provided by the industry. The revisions to the draft standard add clarity regarding timeframe. The Time Horizons were modified and changed to "Long-term Planning." Requirement R1 has been revised and the reformatting addresses your comment.				
Larry D Grimm	Texas Reliability Entity	10	Negative	This FAC-013-2 standard should state that it is not applicable in the ERCOT region. See FERC Order 729, Â¶ 298 (see also Â¶ 292-293), where FERC states that certain MOD standards should not apply in the ERCOT region. FAC-013 represents an extension of the MOD standards (which relate to calculation of available transfer capability) applied in the planning horizon. Entities in ERCOT should be exempt from FAC-013 for the same reason they are exempt from the MOD standards, because ERCOT does not need to address transmission allocation issues either in the operating horizon or in the planning horizon. To the extent that ERCOT does planning studies to examine transfers, those studies are related more to economic planning than to reliability.
Response: Per the NERC Standards Process Manual, "It is the responsibility of the entity that needs a variance to identify that need and initiate the processing of that variance through the submittal of a SAR that includes a clear definition of the basis for the variance." The SDT cannot take this action on behalf of a region or Interconnection. The concept of transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The standard's emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values. The SDT believes there is a reliability related need for this assessment to be conducted. The SDT does not believe the TPL standards adequately cover the need at this time.				
Thomas E Washburn	Florida Municipal Power Pool	6	Negative	Unofficial Comment Form for Project 2010-10 - Modifications to FAC-012 and FAC-013 for Order 729 - Draft FAC-013-2 Standard Please DO NOT use this form. Please use the electronic comment form located at the link below to submit comments on the proposed SAR and modifications proposed FAC-013-2 - Planning Transfer Capability. Comments must be submitted by November 3, 2010. If you have questions please contact Darrel Richardson at Darrel.richardson@nerc.net or by telephone at 609-613-1848. https://www.nerc.net/nercsurvey/Survey.aspx?s=e90004c891d2475ea8f1f74a35d5e2ba Background Information: The SAR for Project 2010-10 - Modifications to FAC-012 and FAC-013 for Order 729 proposes modifications to the following standards: o FAC-012-1 - Transfer Capability Methodology o FAC-013-1 - Establish and Communicate Transfer Capabilities In Order 729, FERC ruled that the ATC standards developed in Project 2006-07 did not completely address the topics covered in FAC-012 and -013 and did not fully address the associated directives from Order 693. Accordingly, FERC denied the portions of the implementation plan that would have retired these standards, and instead

Voter	Entity	Segment	Vote	Comment
				directed NERC to use the standards development process to make changes to the FAC standards and file those changes with FERC no later than 60 days prior to the effective date of the standards, which is April 1, 2011 (requiring the proposed changes to be filed on or before January 31, 2011). NERC has an obligation to address FERC's directives. It is the intent to identify all the applicable FERC directives and incorporate them in the draft standard. A second draft of the proposed standard has been developed that attempts to address the applicable FERC directives as well as address concerns raised by the industry during the first posting. Please review the proposed draft standard in its entirety and answer the following questions by using the electronic comment form. You do not have to answer all questions. Enter all comments in Simple Text Format. 1. The SDT has modified the definition of Planning Transfer Capability (PTC). The definition now reads "The Transfer Capability that is calculated for the planning period beyond 13 months." Do you agree that the revised definition provides additional clarity as to the time period for the calculations? 0 Yes 1 No Comments: It is unclear whether PTC is allegorical to TTC or to ATC. The term should be modified to clarify whether PTC is the total or the incremental available. Without this clarity, on PC might calculate a total whereas its neighboring PC calculate an incremental available value and the numbers will be dramatically different causing confusion. Also, it leaves the values of PTC open to interpretation. FMPA recommends that PTC be calculated as the total; however, the PC should also report the TRM, CBM and existing long term firm commitments assumed so that entities understand that the total may not all be available (e.g., in the PTCMD). 2. The SDT has modified the definition of Planning Transfer Capability Implementation Document (PTCID) so that it is now called Planning Transfer Capability Methodology Document (PTCMD). The definition now reads "A document that describes the process for calculating Planning Transfer Capability (PTC)." Do you agree that the revised definition provides additional clarity as to the purpose of the document? 0 Yes 1 No Comments: Mention should be made of the assumptions as well as the process / method 3. The SDT has modified the Requirements to include data and modeling information as well as provide for additional clarity regarding the intent of the Requirement. Do you agree that the revised Requirements accomplish

Voter	Entity	Segment	Vote	Comment
				this goal? 0 Yes 1 No Comments: A new sub-requirement should be added that requires listing of existing long term firm point to point transmission service that would consume PTC (assuming PTC is a “total” and not an “available” number). 3. The SDT has modified the VRFs to better align with the risk associated with the Requirements. Do you agree that the VRFs are now more consistent with regards to the risk associated with the Requirements? 1 Yes 0 No Comments: 4. The SDT has modified the Measures to better align with the Requirements. Do you agree that the Measures are now more consistent with the Requirements? 0 Yes 1 No Comments: M3 and M4 are simply restatements of the requirements. FMPA suggests adding “such as (examples of evidence)” statements similar to those provided in M1, M2 and M5. 6. The SDT has modified the VSLs to better align with the severity of non-compliance associated with the Requirements. Do you agree that the VSLs are now more consistent with regards to the severity of non-compliance associated with the Requirements? 1 Yes 0 No Comments: 7. When reviewing the mapping document posted with the proposed FAC-013-2 standard, do you believe that the proposed standard (considering only the requirements assigned to the Planning Coordinator) will be lead to an improvement in reliability when compared to the standards it proposes to replace? 1 Yes 0 No
Response: The revised standard does not require the calculation of Transfer Capabilities – it requires an assessment of Transfer Capability. The PTC definition has been deleted based on industry comments and the concept of a transfer capability assessment in the Near-Term Planning Horizon has been clarified to avoid confusion and draw distinction from the calculation of ATC/AFC/TTC performed in the operating horizon. The revised standard’s emphasis is on assessment of future reliability and facilities that may be impacted by changes in transfers - not specific transfer capability values. Regarding comments 2 through 7 please refer to the response provided in the formal comment form.				

A. Introduction

1. **Title:** **Establish and Communicate Transfer Capabilities**

2. **Number:** FAC-013-1

3. **Purpose:** To ensure that Transfer Capabilities used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

4. **Applicability**

   4.1. Reliability Coordinator required by its Regional Reliability Organization to establish inter-regional and intra-regional Transfer Capabilities

   4.2. Planning Authority required by its Regional Reliability Organization to establish inter-regional and intra-regional Transfer Capabilities

5. **Effective Date:** October 7, 2006

B. Requirements

R1. The Reliability Coordinator and Planning Authority shall each establish a set of inter-regional and intra-regional Transfer Capabilities that is consistent with its current Transfer Capability Methodology.

R2. The Reliability Coordinator and Planning Authority shall each provide its inter-regional and intra-regional Transfer Capabilities to those entities that have a reliability-related need for such Transfer Capabilities and make a written request that includes a schedule for delivery of such Transfer Capabilities as follows:

R2.1. The Reliability Coordinator shall provide its Transfer Capabilities to its associated Regional Reliability Organization(s), to its adjacent Reliability Coordinators, and to the Transmission Operators, Transmission Service Providers and Planning Authorities that work in its Reliability Coordinator Area.

R2.2. The Planning Authority shall provide its Transfer Capabilities to its associated Reliability Coordinator(s) and Regional Reliability Organization(s), and to the Transmission Planners and Transmission Service Provider(s) that work in its Planning Authority Area.

C. Measures

M1. The Reliability Coordinator and Planning Authority shall each be able to demonstrate that it developed its Transfer Capabilities consistent with its Transfer Capability Methodology.

M2. The Reliability Coordinator and Planning Authority shall each have evidence that it provided its Transfer Capabilities in accordance with schedules supplied by the requestors of such Transfer Capabilities.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility
   Regional Reliability Organization

   1.2. Compliance Monitoring Period and Reset Timeframe

   The Reliability Coordinator and Planning Authority shall each verify compliance through self-certification submitted to the Compliance Monitor annually. The Compliance

Monitor may conduct a targeted audit once in each calendar year (January–December) and an investigation upon a complaint to assess compliance.

The Performance-Reset Period shall be twelve months from the last finding of non-compliance.

1.3. Data Retention

The Planning Authority and Reliability Coordinator shall each keep documentation for 12 months. In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant.

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Planning Authority and Reliability Coordinator shall each make the following available for inspection during a targeted audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 Transfer Capability Methodology.

1.4.2 Inter-regional and Intra-regional Transfer Capabilities.

1.4.3 Evidence that Transfer Capabilities were distributed.

1.4.4 Distribution schedules provided by entities that requested Transfer Capabilities.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: Not all requested Transfer Capabilities were provided in accordance with their respective schedules.

2.3. Level 3: Transfer Capabilities were not developed consistent with the Transfer Capability Methodology.

2.4. Level 4: No requested Transfer Capabilities were provided in accordance with their respective schedules.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
1	08/01/05	1. Changed incorrect use of certain hyphens (-) to “en dash (–).” 2. Lower cased the word “draft” and “drafting team” where appropriate. 3. Changed Anticipated Action #5, page 1, from “30-day” to “Thirty-day.” 4. Added or removed “periods.”	01/20/05

A. Introduction

1. **Title:** **Transfer Capability Methodology**
2. **Number:** FAC-012-1
3. **Purpose:** To ensure that Transfer Capabilities used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.
4. **Applicability**
   - **4.1.** Reliability Coordinator required by its Regional Reliability Organization to establish inter-regional and intra-regional Transfer Capabilities
   - **4.2.** Planning Authority required by its Regional Reliability Organization to establish inter-regional and intra-regional Transfer Capabilities
5. **Effective Date:** August 7, 2006

B. Requirements

R1. The Reliability Coordinator and Planning Authority shall each document its current methodology used for developing its inter-regional and intra-regional Transfer Capabilities (Transfer Capability Methodology). The Transfer Capability Methodology shall include all of the following:

R1.1. A statement that Transfer Capabilities shall respect all applicable System Operating Limits (SOLs).

R1.2. A definition stating whether the methodology is applicable to the planning horizon or the operating horizon.

R1.3. A description of how each of the following is addressed, including any reliability margins applied to reflect uncertainty with projected BES conditions:

R1.3.1. Transmission system topology

R1.3.2. System demand

R1.3.3. Generation dispatch

R1.3.4. Current and projected transmission uses

R2. The Reliability Coordinator shall issue its Transfer Capability Methodology, and any changes to that methodology, prior to the effectiveness of such changes, to all of the following:

R2.1. Each Adjacent Reliability Coordinator and each Reliability Coordinator that indicated a reliability-related need for the methodology.

R2.2. Each Planning Authority and Transmission Planner that models any portion of the Reliability Coordinator's Reliability Coordinator Area.

R2.3. Each Transmission Operator that operates in the Reliability Coordinator Area.

R3. The Planning Authority shall issue its Transfer Capability Methodology, and any changes to that methodology, prior to the effectiveness of such changes, to all of the following:

R3.1. Each Transmission Planner that works in the Planning Authority's Planning Authority Area.

R3.2. Each Adjacent Planning Authority and each Planning Authority that indicated a reliability-related need for the methodology.

R3.3. Each Reliability Coordinator and Transmission Operator that operates any portion of the Planning Authority's Planning Authority Area.

R4. If a recipient of the Transfer Capability Methodology provides documented technical comments on the methodology, the Reliability Coordinator or Planning Authority shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the Transfer Capability Methodology and, if no change will be made to that Transfer Capability Methodology, the reason why.

C. Measures

M1. The Planning Authority and Reliability Coordinator's methodology for determining Transfer Capabilities shall each include all of the items identified in FAC-012 Requirement 1.1 through Requirement 1.3.4.

M2. The Reliability Coordinator shall have evidence it issued its Transfer Capability Methodology in accordance with FAC-012 Requirement 2 through Requirement R2.3.

M3. The Planning Authority shall have evidence it issued its Transfer Capability Methodology in accordance with FAC-012 Requirement 3 through Requirement 3.3.

M4. If the recipient of the Transfer Capability Methodology provides documented comments on its technical review of that Transfer Capability Methodology, the Reliability Coordinator or Planning Authority that distributed that Transfer Capability Methodology shall have evidence that it provided a written response to that commenter in accordance with FAC-012 Requirement 4.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Timeframe

Each Planning Authority and Reliability Coordinator shall self-certify its compliance to the Compliance Monitor at least once every three years. New Planning Authorities and Reliability Coordinators shall each demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last finding of non-compliance.

1.3. Data Retention

The Planning Authority and Reliability Coordinator shall each keep all superseded portions to its Transfer Capability Methodology for 12 months beyond the date of the change in that methodology and shall keep all documented comments on the Transfer Capability Methodology and associated responses for three years. In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant.

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Planning Authority and Reliability Coordinator shall each make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 Transfer Capability Methodology.

1.4.2 Superseded portions of its Transfer Capability Methodology that have been made within the past 12 months.

1.4.3 Documented comments provided by a recipient of the Transfer Capability Methodology on its technical review of the Transfer Capability Methodology, and the associated responses.

2. Levels of Non-Compliance

2.1. Level 1: There shall be a level one non-compliance if either of the following conditions exists:

2.1.1 The Transfer Capability Methodology is missing any one of the required statements or descriptions identified in FAC-012 R1.1 through R1.3.4.

2.1.2 No evidence of responses to a recipient's comments on the Transfer Capability Methodology.

2.2. Level 2: The Transfer Capability Methodology is missing a combination of two of the required statements or descriptions identified in FAC-012 R1.1 through R1.3.4, or a combination thereof.

2.3. Level 3: The Transfer Capability Methodology is missing a combination of three or more of the required statements or descriptions identified in FAC-012 R1.1 through R1.3.4.

2.4. Level 4: The Transfer Capability Methodology was not issued to all of the required entities.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
1	08/01/05	1. Lower cased the word "draft" and "drafting team" where appropriate. 2. Changed incorrect use of certain hyphens (-) to "en dash" (–) and "em dash (—)." 3. Changed "Timeframe" to "Time Frame" in item D, 1.2.	01/20/06

Mapping Table Showing Translation of FAC-012-1 – Transfer Capability Methodology and FAC-013-1 – Establish and Communicate Transfer Capabilities into FAC-013-2 – Planning Transfer Capability

Standard: FAC-012-1- Transfer Capability Methodology		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language in FAC-013-2/Comments**
R1. The Reliability Coordinator and Planning Authority shall each document its current methodology used for developing its inter-regional and intra-regional Transfer Capabilities (Transfer Capability Methodology). The Transfer Capability Methodology shall include all of the following: R1.1. A statement that Transfer Capabilities shall respect all applicable System Operating Limits (SOLs). R1.2. A definition stating whether the methodology is applicable to the planning horizon or the operating horizon. R1.3. A description of how each of the following is addressed, including any reliability margins applied to reflect uncertainty with projected BES conditions: R1.3.1. Transmission system topology R1.3.2. System demand R1.3.3. Generation dispatch R1.3.4. Current and projected	This Requirement has been moved into FAC-013-2 Requirement R1	*The Reliability Coordinator has been removed as an applicable entity in FAC-013-2.* **R1.** Each Planning Coordinator shall have a documented methodology it uses to perform an annual assessment of Transfer Capability in the Near-Term Transmission Planning Horizon (Transfer Capability Methodology). The Transfer Capability Methodology shall include, at a minimum, the following information: [*Violation Risk Factor: Lower*] [*Time Horizon: Long-term Planning*] **1.1.** Criteria for the selection of the transfers to be assessed. **1.2.** A statement that the assessment shall respect known System Operating Limits (SOLs). **1.3.** A statement that the assumptions and criteria used to perform the assessments are consistent with the Planning Coordinator's planning practices. **1.4.** A description of how each of the following assumptions and criteria used in performing the assessment are addressed: 1.4.1 Generation dispatch, including but not limited to planned outages, additions and retirements.

Standard: FAC-012-1- Transfer Capability Methodology		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language in FAC-013-2/Comments**
transmission uses		1.4.2 Transmission system topology, including but not limited to planned Transmission outages, additions, and retirements. 1.4.3 System demand. 1.4.4 Current approved and projected Transmission uses. 1.4.5 Parallel path (loop flow) adjustments. 1.4.6 Contingencies 1.4.7 Monitored Facilities. **1.5.** A description of how simulations of transfers are performed through the adjustment of generation, Load or both.
R2. The Reliability Coordinator shall issue its Transfer Capability Methodology, and any changes to that methodology, prior to the effectiveness of such changes, to all of the following: R2.1. Each Adjacent Reliability Coordinator and each Reliability Coordinator that indicated a reliability-related need for the methodology. R2.2. Each Planning Authority and Transmission Planner that models any portion of the Reliability Coordinator's Reliability Coordinator Area. R2.3. Each Transmission Operator that	This Requirement has been removed from FAC-013-2.	*FAC-013-2 only applies to the Planning Coordinator.*

Standard: FAC-012-1- Transfer Capability Methodology		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language in FAC-013-2/Comments**
operates in the Reliability Coordinator Area.		
R3. The Planning Authority shall issue its Transfer Capability Methodology, and any changes to that methodology, prior to the effectiveness of such changes, to all of the following: R3.1. Each Transmission Planner that works in the Planning Authority's Planning Authority Area. R3.2. Each Adjacent Planning Authority and each Planning Authority that indicated a reliability-related need for the methodology. R3.3. Each Reliability Coordinator and Transmission Operator that operates any portion of the Planning Authority's Planning Authority Area.	This Requirement has been moved into FAC-013-2 Requirement R2.	R2. Each Planning Coordinator shall issue its Transfer Capability Methodology, and any revisions to the Transfer Capability Methodology, to the following entities prior to the effectiveness of such revisions: 2.1. Each Planning Coordinator adjacent to the Planning Coordinator's planning coordinator area. 2.2. Each Transmission Planner within the Planning Coordinator's planning coordinator area. 2.3. Any other functional entity that has a reliability-related need for the annual assessment of Transfer Capabilities and makes a written request for such assessments. *FAC-012-1 Requirement R3.3 has been modified to include any functional entity that has a reliability-related need (FAC-013-2 Requirement R2 Part 2.3).*
R4. If a recipient of the Transfer Capability Methodology provides documented technical comments on the methodology, the Reliability Coordinator or Planning Authority shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the Transfer Capability Methodology and, if no change will be made to that Transfer Capability Methodology, the reason why.	This Requirement has been moved into FAC-013-2 Requirement R3.	R3. If a recipient of the Transfer Capability Methodology provides documented technical comments on the methodology, the Planning Coordinator shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the Transfer Capability Methodology and, if no change will be made to that Transfer Capability Methodology, the reason why.

Standard: FAC-013-1 - Establish and Communicate Transfer Capabilities		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language in FAC-013-2/Comments**
R1. The Reliability Coordinator and Planning Authority shall each establish a set of inter-regional and intra-regional Transfer Capabilities that is consistent with its current Transfer Capability Methodology.	This Requirement has been moved into FAC-013-2 Requirement R4.	R4. Each Planning Coordinator shall document an assessment based on the simulations performed in accordance with their Transfer Capability Methodology for at least one year in the Near-Term Transmission Planning Horizon during each calendar year.
R2. The Reliability Coordinator and Planning Authority shall each provide its inter-regional and intra-regional Transfer Capabilities to those entities that have a reliability-related need for such Transfer Capabilities and make a written request that includes a schedule for delivery of such Transfer Capabilities as follows: R2.1. The Reliability Coordinator shall provide its Transfer Capabilities to its associated Regional Reliability Organization(s), to its adjacent Reliability Coordinators, and to the Transmission Operators, Transmission Service Providers and Planning Authorities that work in its Reliability Coordinator Area.	This Requirement has been moved into FAC-013-2 Requirement R5.	*The Reliability Coordinator is not an applicable entity in FAC-013-2 therefore FAC-013-1 Requirement R2.1 has been removed.* R5. The Planning Coordinator shall make its assessment available no later than 45 calendar days following completion of the assessment to those entities identified in Requirement R2. *FAC-013-1 Requirement 2.2 has been modified to include adjacent Planning Coordinators, Transmission Planners within the Planning Coordinator area and any functional entity that has a reliability-related need (FAC-013-2 Requirement R2 Part 2.1 through Part 2.3).*

Standard: FAC-013-1 - Establish and Communicate Transfer Capabilities		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language in FAC-013-2/Comments**
R2.2. The Planning Authority shall provide its Transfer Capabilities to its associated Reliability Coordinator(s) and Regional Reliability Organization(s), and to the Transmission Planners and Transmission Service Provider(s) that work in its Planning Authority Area.		

FAC-013-2 WHITEPAPER

Through FERC Orders 693 (paragraphs 782 and 794) and 729 (paragraphs 278, 279, 289, 290 and 291), FERC directed NERC to establish a standard requiring Planning Coordinators to calculate transfer capability in the planning horizon and communicate the results. In the FERC Order approving the MOD standards related to ATC/AFC calculations (MOD-001, MOD-028, MOD-029, and MOD-030), FERC did not approve NERC's request to withdraw FAC-012-1, nor did they approve the retirement of FAC-013-1. With respect to these two Reliability Standards, the Commission disagreed with NERC that they are wholly superseded by the MOD Reliability Standards.

- The Commission noted that, under FAC-012-1, Reliability Coordinators and Planning Authorities would be required to document the methodology used to establish inter-regional and intra-regional transfer capabilities and to state whether the methodology is applicable to the planning horizon or the operating horizon.

- The Commission also noted that, under FAC-013-1, Reliability Coordinators and Planning Authorities are required to establish a set of inter-regional and intra-regional transfer capabilities that are consistent with the methodology documented under FAC-012-1, which could require the calculation of transfer capabilities for both the planning horizon and the operating horizon.

- The Commission posited that these FAC Reliability Standards were necessary because the proposed MOD Reliability Standards provide only for the calculation of available transfer capability and its components, including total transfer capability, in the operating horizon. Thus, the Commission stated, the proposed MOD Reliability Standards do not govern the calculation of transfer capabilities in the planning horizon, i.e., beyond 13 months in the future.

- The Commission also noted, that the calculation of transfer capabilities in the planning horizon (years one through five) may not be so accurate to support long-term scheduling of the transmission system but that such forecasts will be useful for long-term planning, in general, by measuring sufficient long-term capacity needed to ensure the reliable operation of the Bulk-Power System.

- The Commission stated that the responsibility for calculation of transfer capabilities in the planning horizon would be appropriately assigned to the Planning Coordinator and not the Reliability Coordinator.

Consistent with the above philosophy and to address FERC's concerns, FAC-013-2 requires that Planning Coordinators have a current documented methodology for use in performing an annual assessment of Transfer Capability in the Near-Term Planning Horizon (Transfer Capability Methodology). FAC-013-2 is only applicable to the Planning Coordinator. The purpose of the standard is to add to the Planning Coordinator's "portfolio of knowledge" for planning for future reliable operation of the Bulk Electric System (BES). The TPL standards define the studies to be performed, the performance requirements for the BES and the details of the required assessments. FAC-013-2 is intended to identify potential future weaknesses in the system by performance of tests - application of bulk energy transfers to stress the system. FAC-013-2 adds to the understanding of system performance obtained through application of the TPL standards, providing knowledge of potential facilities requiring additional focus and analysis.

Identification of new System Operating Limits is not the intent of FAC-013-2. Known System Operating Limits associated with facility ratings, transient stability ratings, voltage stability ratings, and system voltage limits that have been identified in other planning and operating studies must be respected in performing the assessment. In addition, this information is not intended in any way to be associated with the granting or denial of transmission service. FAC-013-2 assessments of transfer capability are also not intended to supersede nor replace calculations done to meet FAC-010 and FAC-014 requirements related to calculation of System Operating Limits (SOL). SOL calculations are performed according to the specific requirements of FAC-010 and FAC-014. FAC-013-2 allows the Planning Coordinator to develop its Transfer Capability Methodology based on knowledge of its system's sensitivity to transfers and significance of Facilities to reliability, within the framework provided by FAC-013-2.

Additionally, the standard is not intended to supersede nor replace transfer tests performed as part of specific planning processes internal to a Balancing Authority, such as generation or load deliverability tests which are not specifically addressed by this standard.

Requirement R1, Part 1.4 requires a description of several elements that must be included in the Transfer Capability Methodology. This description is intended to provide context for the assessment results. Knowledge of these details of the Transfer Capability Methodology will allow those receiving assessment data to better understand the assessments and their potential impact on BES reliability. Some guidance is provided for each of the required elements:

> Generation dispatch should include a discussion of how generation outages are included in the models used for the assessment; whether known outages are included or other methods (e.g. Monte Carlo) are used to represent outages of generation, and if any generation related operating guides are utilized. It should also identify if generation retirements are modeled and if new/proposed generation is included in the models.
>
> Transmission system topology should include a discussion of how transmission outages are included in the models used for the assessment; whether known outages are included or other methods are used to represent transmission outages. Additionally, identification of whether transmission facility retirements are modeled and if new/proposed transmission facilities are included in the models.

System demand should include a description of the models used (e.g. MMWG, regional, other), seasons, load levels and conditions selected calculation.

Current and projected transmission uses should include a description for how firm and non-firm transmission service is modeled.

Any parallel path impacts (loop flows) that are added to the base models or affect study results should be explained.

A description of the contingencies evaluated should be provided to explain the types of contingencies (e.g. N-1, N-1-1) that drive the study results.

A description of the facilities monitored should be provided to explain the areas monitored and the kV level of the facilities.

Requirement R1, Part R1.3 “A statement that the assumptions and criteria used to perform the assessment are consistent with the Planning Coordinator’s planning practices.”, is intended to provide consistency in the performance of the assessment of transfer capability and the planning practices used in the evaluation of the reliability of the BES.

Requirements R2 and R3 are intended to facilitate the necessary communication of the Transfer Capability Methodology and ensure an understanding of the methodology by those NERC registered functional entities having a reliability related need – primarily the Transmission Planners in the Planning Coordinator’s area and neighboring Planning Coordinators.

Requirements R4 through R6 ensure an annual assessment of transfer capability is performed and that the data and results are communicated to those same entities that have a reliability related need for those results. Communication and response to comments on the methodology and comments on the annual assessment provide for coordination of planning between the affected entities.

The application of FAC-013-2 will provide an assessment of the robustness of the future transmission system and facilitate communication between adjacent Planning Coordinators. FAC-013-2 addresses FERC's concerns regarding transfer capability in the planning horizon and provides important information that Planning Coordinators will be able to apply in their efforts to reliably plan the BES.

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for Project 2010-10 — Modifications to FAC-012 and FAC-013 for Order 729 — Draft FAC-013-2 Standard

Please **DO NOT** use this form. Please use the electronic comment form located at the link below to submit comments on the proposed SAR and modifications proposed FAC-013-2 — Planning Transfer Capability. Comments must be submitted by **January 8, 2011**. If you have questions please contact Darrel Richardson at Darrel.richardson@nerc.net or by telephone at 609-613-1848.

http://www.nerc.com/filez/standards/Project2010-10_FAC_Order_729.html

Background Information:

The SAR for Project 2010-10 – Modifications to FAC-012 and FAC-013 for Order 729 proposes modifications to the following standards:

- FAC-012-1 — Transfer Capability Methodology
- FAC-013-1 — Establish and Communicate Transfer Capabilities

In Order 729, FERC ruled that the ATC standards developed in Project 2006-07 did not completely address the topics covered in FAC-012 and -013 and did not fully address the associated directives from Order 693. Accordingly, FERC denied the portions of the implementation plan that would have retired these standards, and instead directed NERC to use the standards development process to make changes to the FAC standards and file those changes with FERC no later than 60 days prior to the effective date of the standards, which is currently believed to be on or after April 1, 2011 (requiring the proposed changes to be filed on or before January 28, 2011).

NERC has an obligation to address FERC's directives. It was the intent to identify all the applicable FERC directives and incorporate them in the draft standard. A second draft of the proposed standard has been developed that attempts to address the applicable FERC directives as-well-as address concerns raised by the industry during the first posting. Please review the proposed draft standard in its entirety and answer the following questions by using the electronic comment form.

You do not have to answer all questions. Enter all comments in Simple Text Format.

1. The SDT has defined the term Near-Term Transmission Planning Horizon. The definition reads “The transmission planning period that covers year’s one through five.” (This definition was originally developed by the Assess Transmission Future Needs SDT and has been moved to this project as this project will be completed before the Assess Transmission Future Needs project.) Do you agree that this term provides clarity as to the period the standard applies?

   ☐ Yes

   ☐ No

   Comments:

2. The SDT has modified the Purpose statement. The Purpose statement now reads “To ensure that Planning Coordinators have a methodology for, and perform an annual assessment of the ability to transfer energy (in the Near-Term Transmission Planning Horizon) to identify potential future weaknesses and limiting Facilities that could impact the reliability of the Bulk Electric System (BES).” Do you agree that the revised Purpose statement provides greater clarity as to what the standard is intended to accomplish?

   ☐ Yes

   ☐ No

   Comments:

3. The SDT has added a Requirement R6. The Requirement R6 reads “If a recipient of a documented Transfer Capability assessment requests data to support the assessment, the Planning Coordinator shall provide such data to that entity within 45 calendar days of receipt of the request.” Do you agree that the Requirement is necessary for verification of the assessment?

   ☐ Yes

   ☐ No

   Comments:

4. The SDT has modified the VSLs to better align with the Requirements. Do you agree that the revised VSLs are now appropriately aligned with the Requirements?

   ☐ Yes

   ☐ No

   Comments:

5. Please provide any other comments (that you have not already provided in response to the questions above) that you have on the proposed standard.

   Comments:

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan for Standard FAC-013-2
Assessment of Transfer Capability for the Near-term Transmission Planning Horizon

Prerequisite Approvals
There are no Standard Authorization Requests (SARs) that must be implemented before this standard can be implemented.

FAC-013-2 cannot be implemented before the following standards become effective:

- MOD-001-1 — Available Transmission System Capability
- MOD-028-1 — Area Interchange Methodology
- MOD-029-1 — Rated System Path Methodology
- MOD-030-2 — Flowgate Methodology

New or Modified Definitions
The following definitions shall become effective when FAC-013-2 becomes effective:

Near-Term Transmission Planning Horizon: The tranmission planning period that covers years one through five.

Modified Standards
FAC-012-1 and FAC-013-1 should be retired when FAC-013-2 becomes effective.

FAC-012-1 – Transfer Capability Methodology
FAC-013-1 – Establish and Communicate Transfer Capabilities

Compliance with Standards
Once the standard becomes effective, the responsible entity identified in the applicability section of the standard must comply with the requirements. This includes:

- Planning Coordinator

Proposed Effective Date
In those jurisdictions where regulatory approval is required, the latter of either the first day of the first calendar quarter twelve months after applicable regulatory approval or the first day of the first calendar quarter six months after MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-2 are effective.

In those jurisdictions where no regulatory approval is required, the latter of either the first day of the first calendar quarter twelve months after Board of Trustees adoption or the first day of the first calendar quarter six months after MOD-001-1, MOD-028-1, MOD-029-1 and MOD-030-2 are effective.

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Implementation Plan for Standard FAC-013-2 — Assessment of ~~Planning~~ Transfer Capability for the Near-term Transmission Planning Horizon

Prerequisite Approvals

There are no Standard Authorization Requests (SARs) that must be implemented before this standard can be implemented.

FAC-013-2 cannot be implemented before the following standards become effective:

- MOD-001-1 — Available Transmission System Capability
- MOD-028-1— Area Interchange Methodology
- MOD-029-1 — Rated System Path Methodology
- MOD-030-2 — Flowgate Methodology

New or Modified Definitions

The following definitions shall become effective when FAC-013-2 becomes effective:

> ~~**Planning Transfer Capability (PTC):** The Transfer Capability that is calculated for the planning period beyond 13 months.~~
>
> ~~**Planning Transfer Capability Mehtodology Document (PTCMD):** A document that describes the process for calculating Planning Transfer Capability (PTC).~~

Near-Term Transmission Planning Horizon: The tranmission planning period that covers years one through five.

Modified Standards

FAC-012-1 and FAC-013-1 should be retired when FAC-013-2 becomes effective.

> FAC-012-1 – Transfer Capability Methodology
> FAC-013-1 – Establish and Communicate Transfer Capabilities

Compliance with Standards

Once the standard becomes effective, the responsible entity identified in the applicability section of the standard must comply with the requirements ~~and calculate an initial set of PTCs within the calendar year immediately following the effective date~~. This includes:

- Planning Coordinator

Proposed Effective Date

In those jurisdictions where regulatory approval is required, the latter of either the first day of the first calendar quarter twelve months after applicable regulatory approval or the first day of the first calendar quarter six months after MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-2 are effective.

In those jurisdictions where no regulatory approval is required, the latter of either the first day of the first calendar quarter twelve months after Board of Trustees adoption or the first day of the first calendar quarter six months after MOD-001-1, MOD-028-1, MOD-029-1 and MOD-030-2 are effective.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. The Standards Committee approved the SAR for posting on March 11, 2010.
2. The SAR was posted for industry comment from March 15, 2010 through April 29, 2010.
3. Standards Committee approved moving the project into the standards development phase on March 11, 2020.
4. The Standards Committee appointed the Standard Drafting Team on April 9, 2010.
5. The first draft of the standard was posted for a 45 day comment period on March 15, 2010.
6. The second draft of the proposed standard was posted for a 45 day comment period and successive ballot on September 20, 2010.

Proposed Action Plan and Description of Current Draft:

This is the third posting of the proposed standard and its associated implementation plan for a 30 day comment period and ballot.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Respond to comments on the third draft of the proposed standard	December 2010
2. Respond to comments on the initial ballot of the proposed standard	December 2010
3. Conduct a re-circulation ballot for 10 days.	January 2011
4. BOT adoption.	January 2011

Definitions of Terms Used in Standard

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

Near-Term Transmission Planning Horizon: The tranmission planning period that covers years one through five.

A. Introduction

1. Title: **Assessment of Transfer Capability for the Near-Term Transmission Planning Horizon.**

2. Number: FAC-013-2

3. Purpose: To ensure that Planning Coordinators have a methodology for, and perform an annual assessment of, the ability to transfer energy (in the Near-Term Transmission Planning Horizon) to identify potential future weaknesses and limiting Facilities that could impact the reliability of the Bulk Electric System (BES).

4. Applicability

4.1. Planning Coordinators

5. Effective Date:

In those jurisdictions where regulatory approval is required, the latter of either the first day of the first calendar quarter twelve months after applicable regulatory approval or the first day of the first calendar quarter six months after MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-2 are effective.

In those jurisdictions where no regulatory approval is required, the latter of either the first day of the first calendar quarter twelve months after Board of Trustees adoption or the first day of the first calendar quarter six months after MOD-001-1, MOD-028-1, MOD-029-1 and MOD-030-2 are effective.

B. Requirements

R1. Each Planning Coordinator shall have a documented methodology it uses to perform an annual assessment of Transfer Capability in the Near-Term Transmission Planning Horizon (Transfer Capability Methodology). The Transfer Capability Methodology shall include, at a minimum, the following information: [*Violation Risk Factor: Lower*] [*Time Horizon: Long-term Planning*]

1.1. Criteria for the selection of the transfers to be assessed.

1.2. A statement that the assessment shall respect known System Operating Limits (SOLs).

1.3. A statement that the assumptions and criteria used to perform the assessments are consistent with the Planning Coordinator's planning practices.

1.4. A description of how each of the following assumptions and criteria used in performing the assessment are addressed:

1.4.1. Generation dispatch, including but not limited to planned outages, additions and retirements.

1.4.2. Transmission system topology, including but not limited to planned Transmission outages, additions, and retirements.

1.4.3. System demand.

1.4.4. Current approved and projected Transmission uses.

1.4.5. Parallel path (loop flow) adjustments.

1.4.6. Contingencies

1.4.7. Monitored Facilities.

1.5. A description of how simulations of transfers are performed through the adjustment of generation, Load or both.

R2. Each Planning Coordinator shall issue its Transfer Capability Methodology, and any revisions to the Transfer Capability Methodology, to the following entities subject to the following: [Violation *Risk Factor: Lower*] [*Time Horizon: Long-term Planning*]

2.1. Distribute to the following prior to the effectiveness of such revisions:

2.1.1. Each Planning Coordinator adjacent to the Planning Coordinator's Planning Coordinator area or overlapping the Planning Coordinator's area.

2.1.2. Each Transmission Planner within the Planning Coordinator's Planning Coordinator area.

2.2. Distribute to each other functional entity that has a reliability-related need for the results of the annual assessment of Transfer Capabilities and makes a written request for such assessment results within 30 calendar days of such a request.

R3. If a recipient of the Transfer Capability Methodology provides documented concerns with the methodology, the Planning Coordinator shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the Transfer Capability Methodology and, if no change will be made to that Transfer Capability Methodology, the reason why. [Violation Risk Factor: Lower][Time Horizon: Long-term Planning]

R4. During each calendar year, each Planning Coordinator shall conduct and document a Transfer Capability assessment based on the simulations performed in accordance with its Transfer Capability Methodology for at least one year in the Near-Term Transmission Planning Horizon. [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]

R5. Each Planning Coordinator shall make the documented Transfer Capability assessment results available within 45 calendar days of the completion of the assessment to the recipients of its Transfer Capability Methodology. [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]

R6. If a recipient of a documented Transfer Capability assessment requests data to support the assessment results, the Planning Coordinator shall provide such data to that entity within 45 calendar days of receipt of the request. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

C. Measures

M1. Each Planning Coordinator shall have a Transfer Capability Methodology that includes the information specified in Requirement R1.

M2. Each Planning Coordinator shall have evidence such as dated e-mail or dated transmittal letters that it provided the new or revised Transfer Capability Methodology in accordance with Requirement R2.

M3. Each Planning Coordinator shall have evidence, such as dated e-mail or dated transmittal letters, that the Planning Coordinator provided a written response to that commenter in accordance with Requirement R3.

M4. Each Planning Coordinator shall have evidence such as dated assessment results, that it conducted and documented a Transfer Capability assessment in accordance with Requirement R4.

M5. Each Planning Coordinator shall have evidence, such as dated copies of e-mails or transmittal letters, that it made its documented Transfer Capability assessment available to the entities in accordance with Requirement R5.

M6. Each Planning Coordinator shall have evidence, such as dated copies of e-mails or transmittal letters, that it made its documented Transfer Capability assessment data available in accordance with Requirement R6.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.3. Data Retention

The Planning Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Planning Coordinator shall have its in force Transfer Capability Methodology and any prior versions of the Transfer Capability Methodology that were in force since the last compliance audit to show compliance with Requirement R1.
- The Planning Coordinator shall retain evidence since its last compliance audit to show compliance with Requirement R2.
- The Planning Coordinator shall retain evidence to show compliance with Requirements R3, R4, R5 and R6 for the most recent assessment.
- If a Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time periods specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Planning Coordinator has a Transfer Capability Methodology but failed to address one or two of the items listed in Requirement R1, Part 1.4.	The Planning Coordinator has a Transfer Capability Methodology but failed to incorporate one of the Requirement R1 Parts 1.1,1.2, 1.3 and 1.5 OR The Planning Coordinator has a Planning Transfer Methodology but failed to address three of the items listed in Requirement R1, Part 1.4.	The Planning Coordinator has a Transfer Capability Methodology but failed to incorporate two of the items listed in Requirement R1, Parts 1.1, 1.2, 1.3 and 1.5. OR The Planning Coordinator has a Planning Transfer Methodology but failed to address four of the items listed in Requirement R1, Part 1.4.	The Planning Coordinator did not have a Transfer Capability Methodology. OR The Planning Coordinator had a Transfer Capability Methodology but failed to incorporate three or more of the items listed in Requirement R1, Parts 1.1, 1.2, 1.3 and 1.5. OR The Planning Coordinator has a Planning Transfer Methodology but failed to address more than four of the items listed in Requirement R1, Part 1.4.
R2	The Planning Coordinator notified one or more of the parties specified in Requirement R2 of a new or revised Transfer Capability Methodology after its implementation, but not more than 30 calendar days after its implementation. OR The Planning Coordinator provided the Transfer Capability Methodology	The Planning Coordinator notified one or more of the parties specified in Requirement R2 of a new or revised Transfer Capability Methodology more than 30 calendar days after its implementation, but not more than 60 calendar days after its implementation. OR The Planning Coordinator provided the Transfer Capability Methodology	The Planning Coordinator notified one or more of the parties specified in Requirement R2 of a new or revised Transfer Capability Methodology more than 60 calendar days, but not more than 90 calendar days after its implementation. OR The Planning Coordinator provided the Transfer Capability Methodology more than 60 calendar days but not	The Planning Coordinator failed to notify one or more of the parties specified in Requirement R2 of a new or revised Transfer Capability Methodology more than 90 calendar days after its implementation. OR The Planning Coordinator provided the Transfer Capability Methodology more than 90 calendar days after

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	after receipt of a request but not more than 30 calendar days after receipt of a request.	more than 30 calendar days but not more than 60 calendar days after receipt of a request.	more than 90 calendar days after receipt of a request.	receipt of a request.
R3	The Planning Coordinator provided a documented response to a documented concern with its Transfer Capability Methodology as required in Requirement R3 more than 45 calendar days, but not more than 60 calendar days after receipt of the concern.	The Planning Coordinator provided a documented response to a documented concern with its Transfer Capability Methodology as required in Requirement R3 more than 60 calendar days, but not more than 75 calendar days after receipt of the concern.	The Planning Coordinator provided a documented response to a documented concern with its Transfer Capability Methodology as required in Requirement R3 more than 75 calendar days, but not more than 90 calendar days after receipt of the concern.	The Planning Coordinator failed to provide a documented response to a documented concern with its Transfer Capability Methodology as required in Requirement R3 by more than 90 calendar days after receipt of the concern. OR The Planning Coordinator failed to respond to a documented concern with its Transfer Capability Methodology.
R4.	The Planning Coordinator conducted a Transfer Capability assessment outside the calendar year, but not by more than 30 calendar days.	The Planning Coordinator conducted a Transfer Capability assessment outside the calendar year, by more than 30 calendar days, but not by more than 60 calendar days.	The Planning Coordinator conducted a Transfer Capability assessment outside the calendar year, by more than 60 calendar days, but not by more than 90 calendar days.	The Planning Coordinator failed to conduct a Transfer Capability assessment outside the calendar year by more than 90 calendar days. OR The Planning Coordinator failed to conduct a Transfer Capability assessment.
R5.	The Planning Coordinator made its documented Transfer Capability assessment available to one or more of the recipients of its Transfer Capability Methodology more than 45 calendar days after completion of the assessment but, but not more than 60 calendar days after completion of the assessment.	The Planning Coordinator made its Transfer Capability assessment available to one or more of the recipients of its Transfer Capability Methodology more than 60 calendar days after completion of the assessment, but not more than 75 calendar days after completion of the assessment.	The Planning Coordinator made its Transfer Capability assessment available to one or more of the recipients of its Transfer Capability Methodology more than 75 calendar days after completion of the assessment, but not more than 90 days after completion of the assessment..	The Planning Coordinator failed to make its documented Transfer Capability assessment available to one or more of the recipients of its Transfer Capability Methodology more than 90 days after completion of the assessment. OR The Planning Coordinator failed to

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				make its documented Transfer Capability assessment available to any of the recipients of its Transfer Capability Methodology.
R6.	The Planning Coordinator provided the requested data as required in Requirement R6 more than 45 calendar days after receipt of the request for data, but not more than 60 calendar days after the receipt of the request for data.	The Planning Coordinator provided the requested data as required in Requirement R6 more than 60 calendar days after receipt of the request for data, but not more than 75 calendar days after the receipt of the request for data.	The Planning Coordinator provided the requested data as required in Requirement R6 more than 75 calendar days after receipt of the request for data, but not more than 90 calendar days after the receipt of the request for data.	The Planning Coordinator provided the requested data as required in Requirement R6 more than 90 after the receipt of the request for data. OR The Planning Coordinator failed to provide the requested data as required in Requirement R6.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
1	08/01/05	1. Changed incorrect use of certain hyphens (-) to “en dash (–).” 2. Lower cased the word “draft” and “drafting team” where appropriate. 3. Changed Anticipated Action #5, page 1, from “30-day” to “Thirty-day.” 4. Added or removed “periods.”	01/20/05
2	TBD	1. Modified to be consistent with directives contained in FERC Order 729	TBD

Definitions of Terms Used in Standard

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

Near-Term Transmission Planning ~~Transfer Capability (PTC):~~ Horizon: The ~~Transfer Capability that is calculated for the~~tranmission planning period ~~beyond 13 months~~that covers years one through five.

~~**Planning Transfer Capability Methodology Document (PTCMD):** A document that describes the process for calculating Planning Transfer Capability (PTC).~~

A. Introduction

1. **Title:** **~~Planning~~ Assessment of Transfer Capability for the Near-Term Transmission Planning Horizon.**

2. **Number:** FAC-013-2

3. **Purpose:** To ensure that Planning Coordinators ~~calculate~~have a methodology for, and perform an annual assessment of, the ability to transfer energy (in the Near-Term Transmission Planning ~~Transfer Capabilities using an established method such~~Horizon) to identify potential future weaknesses and limiting Facilities that ~~those forecasts of Transfer Capabilities are available for the reliable planning~~could impact the reliability of the Bulk Electric System (BES).

4. **Applicability**

   4.1. Planning Coordinators~~.~~

5. **Effective Date:**

In those jurisdictions where regulatory approval is required, the latter of either the first day of the first calendar quarter twelve months after applicable regulatory approval or the first day of the first calendar quarter six months after MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-2 are effective.

In those jurisdictions where no regulatory approval is required, the latter of either the first day of the first calendar quarter twelve months after Board of Trustees adoption or the first day of the first calendar quarter six months after MOD-001-1, MOD-028-1, MOD-029-1 and MOD-030-2 are effective.

B. Requirements

R1. Each Planning Coordinator shall ~~prepare and keep current~~have a documented methodology it uses to perform an annual assessment of Transfer Capability in the Near-Term Transmission Planning Horizon (Transfer Capability Methodology~~ Document (PTCMD) that includes~~). The Transfer Capability Methodology shall include, at a minimum, the following information: [*Violation Risk Factor: Lower*] [*Time Horizon: Long-term Planning*]

1.1. Criteria for the selection of the transfers to be assessed.

1.2. A statement that the assessment shall respect known System Operating Limits (SOLs).

1.3. A statement that the assumptions and criteria used to perform the assessments are consistent with the Planning Coordinator's planning practices.

~~1.1.~~1.4. A description of how each of the following assumptions and criteria used in ~~the calculation of Planning Transfer Capabilities (PTCs) to include at a minimum how each of the following~~ performing the assessment are addressed~~, or an explanation for any of the following not used in the calculation of PTC.~~:

1.4.1. Generation dispatch, including ~~expected~~but not limited to planned outages, additions and retirements.

1.4.2. Transmission system topology, including ~~expected transmission~~but not limited to planned Transmission outages, additions, and retirements.

1.4.3. System demand.

1.4.4. Current approved and projected ~~transmission~~Transmission uses.

1.4.5. Parallel path ~~impacts~~ (loop ~~flows)~~flow) adjustments.

1.4.6. Contingencies

- ~~Reliability margins applied to reflect uncertainty with BES conditions.~~

~~**1.2.** A list of all PTCs to be calculated.~~

~~**1.3.** A statement that PTCs shall respect all applicable System Operating Limits (SOLs).~~

~~A statement that the assumptions and criteria used to calculate PTCs are as, or more, limiting than the assumptions and criteria used in the operating horizon~~**1.4.7.** Monitored Facilities.

~~1.4.~~1.5. A description of how simulations of transfers are performed through the adjustment of generation~~/load is adjusted to determine the PTCs identified in Requirement R1, Part 1.2~~, Load or both.

R2. Each Planning Coordinator shall issue its ~~PTCMD~~Transfer Capability Methodology, and any revisions to the ~~PTCMD~~Transfer Capability Methodology, to the following entities ~~prior~~subject to the ~~effectiveness of such revisions~~following: [Violation *Risk Factor: Lower*] [*Time Horizon: Long-term Planning*]

2.1. Distribute to the following prior to the effectiveness of such revisions:

2.1.1. Each Planning Coordinator adjacent to the Planning Coordinator's ~~planning coordinator~~Planning Coordinator area~~.~~ or overlapping the Planning Coordinator's area.

2.1.2. Each Transmission Planner within the Planning Coordinator's ~~planning coordinator~~Planning Coordinator area.

~~2.1.~~2.2. ~~Any~~Distribute to each other functional entity that has a reliability-related need for ~~such PTCs~~ the results of the annual assessment of Transfer Capabilities and makes a written request for such ~~PTCs~~assessment results within 30 calendar days of such a request.

R3. If a recipient of the ~~PTCMD~~Transfer Capability Methodology provides documented ~~technical comments on~~concerns with the methodology, the Planning Coordinator shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the ~~PTCMD~~Transfer Capability Methodology and, if no change will be made to that ~~PTCMD~~Transfer Capability Methodology, the reason why. [Violation Risk Factor: Lower][Time Horizon: Long-term Planning]

R4. ~~Each~~During each calendar year, each Planning Coordinator shall ~~verify,~~conduct and ~~if assumptions or criteria as described~~document a Transfer Capability assessment based on the simulations performed in ~~Requirement 1 Part 1.1 have changed, recalculate its PTCs consistent~~accordance with its ~~PTCMD~~Transfer Capability Methodology for ~~years two through five~~ at least ~~once each calendar year with no more than 15 months between verifications~~one year in the Near-Term Transmission Planning Horizon. [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]

R5. ~~The~~Each Planning Coordinator shall make ~~its PTCs~~the documented Transfer Capability assessment results available ~~no later than 30~~within 45 calendar days ~~(following the verification or recalculation~~ of ~~those PTCs)~~the completion of the assessment to ~~those entities identified in Requirement R2~~the recipients of its Transfer Capability Methodology. [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]

R6. If a recipient of a documented Transfer Capability assessment requests data to support the assessment results, the Planning Coordinator shall provide such data to that entity within 45 calendar days of receipt of the request. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

C. Measures

M1. Each Planning Coordinator shall have a ~~current, dated PTCMD~~Transfer Capability Methodology that includes the information specified in Requirement R1.

M2. Each Planning Coordinator shall have evidence ~~(~~such as dated e-mail or dated transmittal letters ~~along with its dated~~ that it provided the new or revised ~~PTCMD) that it issued its PTCMD and each revision to its PTCMD, to the entities specified~~Transfer Capability Methodology in accordance with Requirement R2 ~~prior to the effectiveness of such revisions~~.

M3. ~~If the recipient of the PTCMD provides documented comments on its technical review of that PTCMD, the~~Each Planning Coordinator ~~that distributed that PTCMD~~ shall have evidence ~~that it~~, such as dated e-mail or dated transmittal letters, that the Planning Coordinator provided a written response to that commenter in accordance with Requirement R3.

M4. Each Planning Coordinator shall have evidence ~~that it verified, and if necessary recalculated, its PTCs consistent with its PTCMD~~such as dated assessment results, that it conducted and documented a Transfer Capability assessment in accordance with Requirement R4.

M5. Each Planning Coordinator shall have evidence, such as dated copies of e-mails or transmittal letters, that it made its ~~PTCs~~documented Transfer Capability assessment available to the entities ~~listed~~ in accordance with Requirement R5 ~~no later than 30 calendar days following their verification or recalculation~~.

M6. Each Planning Coordinator shall have evidence, such as dated copies of e-mails or transmittal letters, that it made its documented Transfer Capability assessment data available in accordance with Requirement R6.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity~~.~~

1.2. Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.3. Data Retention

The Planning Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Planning Coordinator shall ~~maintain~~have its ~~current,~~ in force ~~PTCMD~~Transfer Capability Methodology and any prior versions of the ~~PTCMD~~Transfer Capability Methodology that were in force since the last compliance audit to show compliance with Requirement R1.
- The Planning Coordinator shall ~~maintain~~retain evidence since its last compliance audit to show compliance with Requirement R2.
- The Planning Coordinator shall ~~maintain~~retain evidence to show compliance with Requirements R3, R4, R5 and ~~R5~~R6 for the most recent ~~calendar year plus the current year~~assessment.
- If a Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time periods specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Planning Coordinator has a ~~PTCMD~~Transfer Capability Methodology but failed to address one or two of the items listed in Requirement R1, Part 1.~~1~~4.	The Planning Coordinator has a ~~PTCMD~~Transfer Capability Methodology but failed to incorporate ~~1~~one of the ~~items listed in~~ Requirement R1~~,~~ Parts 1.1, 1.2 ~~through~~, 1.3 and 1.5 OR The Planning Coordinator has a ~~PTCMD~~Planning Transfer Methodology but failed to address ~~two or more~~ three of the items listed in Requirement R1, Part 1.~~1~~4.	The Planning Coordinator has a ~~PTCMD~~Transfer Capability Methodology but failed to incorporate ~~2~~two of the items listed in Requirement R1, Parts 1.~~2 through~~1, 1.2, 1.3 and 1.5. OR The Planning Coordinator has a Planning Transfer Methodology but failed to address four of the items listed in Requirement R1, Part 1.4.	The Planning Coordinator ~~does~~did not have a ~~PTCMD~~Transfer Capability Methodology. OR The Planning Coordinator ~~has a PTCMD~~had a Transfer Capability Methodology but failed to incorporate ~~3~~three or more of the items listed in Requirement R1, Parts 1.~~2 through~~1, 1.2, 1.3 and 1.5. OR The Planning Coordinator has a Planning Transfer Methodology but failed to address more than four of the items listed in Requirement R1, Part 1.4.
R2	The Planning Coordinator notified one or more of the parties specified in Requirement R2 of a new or revised ~~PTCMD~~Transfer Capability Methodology after its implementation, but not more than 30 calendar days after its implementation. OR The Planning Coordinator provided	The Planning Coordinator notified one or more of the parties specified in Requirement R2 of a new or revised ~~PTCMD~~Transfer Capability Methodology more than 30 calendar days after its implementation, but not more than ~~40~~60 calendar days after its implementation. OR The Planning Coordinator provided	The Planning Coordinator notified one or more of the parties specified in Requirement R2 of a new or revised ~~PTCMD~~Transfer Capability Methodology more than ~~40~~60 calendar days, but not more than ~~50~~90 calendar days after its implementation. OR The Planning Coordinator provided	The Planning Coordinator failed to notify one or more of the parties specified in Requirement R2 of a new or revised ~~PTCMD~~Transfer Capability Methodology more than ~~50~~90 calendar days after its implementation. OR The Planning Coordinator provided the Transfer Capability Methodology

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	the Transfer Capability Methodology after receipt of a request but not more than 30 calendar days after receipt of a request.	the Transfer Capability Methodology more than 30 calendar days but not more than 60 calendar days after receipt of a request.	the Transfer Capability Methodology more than 60 calendar days but not more than 90 calendar days after receipt of a request.	more than 90 calendar days after receipt of a request.
R3	The Planning Coordinator provided a documented response to a documented ~~technical comment~~concern with its Transfer Capability Methodology as required in Requirement R3 ~~after~~more than 45 calendar days, but not more than 60 calendar days after receipt of the ~~comment~~concern.	The Planning Coordinator provided a documented response to a documented ~~technical comment~~concern with its Transfer Capability Methodology as required in Requirement R3 ~~after~~more than 60 calendar days, but not more than ~~70~~75 calendar days after receipt of the ~~comment~~concern.	The Planning Coordinator provided a documented response to a documented ~~technical comment~~concern with its Transfer Capability Methodology as required in Requirement R3 ~~after 80~~more than 75 calendar days, but not more than 90 calendar days after receipt of the ~~comment~~concern.	The Planning Coordinator failed to provide a documented response to a documented ~~technical comment~~concern with its Transfer Capability Methodology as required in Requirement R3 by more than 90 calendar days after receipt of the concern. OR The Planning Coordinator failed to respond to a documented concern with its Transfer Capability Methodology.
R4.	The Planning Coordinator conducted a Transfer Capability assessment outside the calendar year, but not by more than 30 calendar days.	The Planning Coordinator conducted a Transfer Capability assessment outside the calendar year, by more than 30 calendar days, but not by more than 60 calendar days.	The Planning Coordinator conducted a Transfer Capability assessment outside the calendar year, by more than 60 calendar days, but not by more than 90 calendar days.	The Planning Coordinator failed to conduct a Transfer Capability assessment outside the calendar year by more than 90 calendar days. OR The Planning Coordinator failed to conduct a Transfer Capability assessment.
~~R4~~R5.	~~The Planning Coordinator failed to verify and recalculate, if necessary, 5% or less of its PTCs, as specified in the PTCMD.~~The Planning Coordinator made its documented Transfer Capability assessment available to one or more of the	~~The Planning Coordinator failed to verify and recalculate, if necessary, more than 5% up to and including 10% of its PTCs as specified in the PTCMD.~~The Planning Coordinator made its Transfer Capability assessment available to one or	The Planning Coordinator ~~failed~~made its Transfer Capability assessment available to ~~verify and recalculate, if necessary,~~one or more of the recipients of its Transfer Capability Methodology more than ~~10% up to and including 15% of its~~	The Planning Coordinator failed to ~~verify and recalculate, if necessary,~~make its documented Transfer Capability assessment available to one or more of the recipients of its Transfer Capability Methodology more than ~~15%~~90

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	recipients of its Transfer Capability Methodology more than 45 calendar days after completion of the assessment but, but not more than 60 calendar days after completion of the assessment.	more of the recipients of its Transfer Capability Methodology more than 60 calendar days after completion of the assessment, but not more than 75 calendar days after completion of the assessment.	~~PTCs, as specified in the PTCMD.~~75 calendar days after completion of the assessment, but not more than 90 days after completion of the assessment..	days after completion of the assessment. OR The Planning Coordinator failed to make its ~~PTCs, as specified in the PTCMD~~documented Transfer Capability assessment available to any of the recipients of its Transfer Capability Methodology.
~~R5~~R6.	The Planning Coordinator ~~notified one or more of the parties specified~~provided the requested data as required in Requirement ~~R5 of its PTCs~~R6 more than ~~30~~45 calendar days after ~~their verification and recalculation~~receipt of the request for data, but not more than 60 calendar days after ~~their verification and recalculation~~the receipt of the request for data.	The Planning Coordinator ~~notified one or more of the parties specified~~provided the requested data as required in Requirement ~~R5 of its PTCs~~R6 more than 60 calendar days after ~~their verification and recalculation~~receipt of the request for data, but not more than ~~70~~75 calendar days after ~~their verification and recalculation~~the receipt of the request for data.	The Planning Coordinator ~~notified one or more of the parties specified~~provided the requested data as required in Requirement ~~R5 of its PTCs~~R6 more than ~~70~~75 calendar days after ~~their verification and recalculation~~receipt of the request for data, but not more than 90 calendar days after the receipt of the request for data.	The Planning Coordinator provided the requested data as required in Requirement R6 more than 90 after the receipt of the request for data. OR The Planning Coordinator failed to ~~notify one or more of~~provide the ~~parties specified~~requested data as required in Requirement ~~R5 of its PTCs after their verification and recalculation~~R6.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
1	08/01/05	1. Changed incorrect use of certain hyphens (-) to "en dash (–)." 2. Lower cased the word "draft" and "drafting team" where appropriate. 3. Changed Anticipated Action #5, page 1, from "30-day" to "Thirty-day." 4. Added or removed "periods."	01/20/05
2	TBD	~~1.~~ Modified to be consistent with directives contained in FERC Order 729 ~~2. Removed Reliability Coordinator as an applicable entity~~ ~~3.~~1.	~~Merged FAC-012 and FAC-013 into FAC-013-2.~~TBD

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Standards Announcement

Successive Formal Comment Period Open
December 10, 2010 – January 8, 2011

Now available at:
http://www.nerc.com/filez/standards/Project2010-10_FAC_Order_729.html

Project 2010-10: FAC Order 729

A 30-day formal comment period for the proposed standard, FAC-013-2 – Planning Transfer Capability and its associated implementation plan is now open **until 8 p.m. Eastern on January 8, 2011**.

Instructions

Please use this electronic form to submit comments on FAC-013-2 and its associated implementation plan. If you experience any difficulties in using the electronic form, please contact Monica Benson at Monica.Benson@nerc.net.

Documents for this project, including an off-line unofficial copy of the questions listed in the comment forms are posted at the following site:
http://www.nerc.com/filez/standards/Project2010-10_FAC_Order_729.html

Note that the changes from the last approved version of FAC-013-1 to the proposed FAC-013-2 are so extensive that developing a redline to show the changes is not practical. The drafting team combined FAC-012-1 and FAC-013-1 into a single proposed standard, FAC-013-2. For reference, the last approved versions of FAC-013-1 and FAC-013-1 have been posted on the project's Web page for easy reference at:
http://www.nerc.com/filez/standards/Project2010-10_FAC_Order_729.html

Next Steps – Successive Ballot and New, Non-binding Poll of VRFs and VSLs

During the last 10 days of the 30-day formal comment period, a successive ballot will be conducted for 10 days. All members of the ballot pool must cast a new ballot since the votes and comments from the last ballot will not be carried over. In addition, members of the ballot pool will need to cast a new opinion on the revised VRFs and VSLs. The drafting team will consider all comments (those submitted with a comment form, and those submitted with a ballot or with the non-binding poll) and will determine whether to make additional changes to the standard and its implementation plan.

Project Background

The proposed standard addresses FERC directives from FERC Order 729 as well as stakeholder comments received during an initial formal comment period and ballot. In Order 729, FERC ruled that the ATC standards developed in Project 2006-07 did not completely address the topics covered in FAC-012 and -013 and did not fully address the associated directives from Order 693. Accordingly, FERC denied the portions of the implementation plan that would have retired these standards, and instead directed NERC to use the standards development process to make changes to the FAC standards and file those changes with FERC no later than 60 days prior to the effective date of the standards, which is April 1, 2011 (requiring the proposed changes to be filed on or before January 31, 2011).

Applicability of Standards in Project
Planning Coordinators

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

For more information or assistance, please contact Monica Benson,
Standards Process Administrator, at monica.benson@nerc.net or at 609.452.8060.

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Standards Announcement

Successive Ballot Window Open
December 30, 2010 – January 8, 2011

Available December 30, 2010 at: https://standards.nerc.net/CurrentBallots.aspx

Project 2010-10: FAC Order 729

A successive ballot for the proposed standard, FAC-013-2 – Planning Transfer Capability and its associated implementation plan, and a concurrent, non-binding poll on revised VRFs and VSLs are being conducted **Thursday, December 30th through 8:00 pm Eastern on Saturday, January 8, 2011**.

Instructions

All members of the ballot pool must cast a new ballot since the votes and comments from the last ballot will not be carried over. In addition, members of the ballot pool will need to cast a new opinion on the revised VRFs and VSLs. The drafting team will consider all comments (those submitted with a comment form, and those submitted with a ballot or with the non-binding poll) and will determine whether to make additional changes to the standard and its implementation plan.

During the successive ballot window, members of the ballot pool associated with this project may log in and submit their votes from the following page: https://standards.nerc.net/CurrentBallots.aspx

Documents for this project, including an off-line unofficial copy of the questions listed in the comment form, are posted at the following site:
http://www.nerc.com/filez/standards/Project2010-10_FAC_Order_729.html

Note that the changes from the last approved version of FAC-013-1 to the proposed FAC-013-2 are so extensive that developing a redline to show the changes is not practical. The drafting team combined FAC-012-1 and FAC-013-1 into a single proposed standard, FAC-013-2. For reference, the last approved versions of FAC-013-1 and FAC-013-1 have been posted on the project's Web page for easy reference at:
http://www.nerc.com/filez/standards/Project2010-10_FAC_Order_729.html

Next Steps

The drafting team will consider all comments (those submitted with a comment form, and those submitted with a ballot or with the non-binding poll) and will determine whether to make additional changes to the standard and its implementation plan.

Project Background

The proposed standard addresses FERC directives from FERC Order 729 as well as stakeholder comments received during an initial formal comment period and ballot. In Order 729, FERC ruled that the ATC standards developed in Project 2006-07 did not completely address the topics covered in FAC-012 and -013 and did not fully address the associated directives from Order 693. Accordingly, FERC denied the portions of the implementation plan that would have retired these standards, and instead directed NERC to use the standards development process to make changes to the FAC standards and file those changes with FERC no later than 60 days prior to the effective date of the standards, which is April 1, 2011 (requiring the proposed changes to be filed on or before January 31, 2011).

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Ballot Results	
Ballot Name:	Project 2010-10 FAC Order 729_non-binding VRF VSL_1210_in
Poll Period:	12/30/2010 - 1/8/2011
Ballot Type:	Successive
Total # Opinions:	256
Total Ballot Pool:	322
Summary Results:	79.50 % of those who registered to participate provided an opinion; 68.84 % of those who provided an opinion indicated support for the VRFs and VSLs that were proposed.

Individual Ballot Pool Results

Segment	Organization	Member	Opinion	Comments
1	Allegheny Power	Rodney Phillips	Affirmative	
1	Ameren Services	Kirit S. Shah	Affirmative	
1	American Electric Power	Paul B. Johnson	Affirmative	
1	American Transmission Company, LLC	Jason Shaver		
1	Arizona Public Service Co.	Robert D Smith	Abstain	
1	Associated Electric Cooperative, Inc.	John Bussman	Abstain	
1	Avista Corp.	Scott Kinney	Abstain	
1	BC Transmission Corporation	Gordon Rawlings	Negative	View
1	Beaches Energy Services	Joseph S. Stonecipher	Negative	View
1	Black Hills Corp	Eric Egge	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	CenterPoint Energy	Paul Rocha	Abstain	
1	Central Maine Power Company	Brian Conroy		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Abstain	
1	City of Vero Beach	Randall McCamish	Negative	View

1	Clark Public Utilities	Jack Stamper	Abstain	
1	Colorado Springs Utilities	Paul Morland	Negative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Abstain	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	John K Loftis	Abstain	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	E.ON U.S.	Larry Monday		
1	East Kentucky Power Coop.	George S. Carruba	Affirmative	
1	Edison Electric Institute	David Batz	Abstain	
1	Empire District Electric Co.	Ralph Frederick Meyer	Affirmative	
1	Entergy Corporation	George R. Bartlett	Abstain	
1	FirstEnergy Energy Delivery	Robert Martinko	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	
1	Gainesville Regional Utilities	Luther E. Fair	Affirmative	
1	GDS Associates, Inc.	Claudiu Cadar		
1	Georgia Transmission Corporation	Harold Taylor, II	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Robert Solomon	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Abstain	View
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JEA	Ted E Hobson		
1	Kansas City Power & Light Co.	Michael Gammon	Abstain	

1	Keys Energy Services	Stan T. Rzad	Negative	View
1	Lake Worth Utilities	Walt Gill	Abstain	
1	Lakeland Electric	Larry E Watt	Negative	View
1	Lee County Electric Cooperative	John W Delucca	Abstain	
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley	Abstain	
1	Manitoba Hydro	Joe D Petaski	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Abstain	
1	National Grid	Saurabh Saksena		
1	Nebraska Public Power District	Richard L. Koch	Abstain	
1	Nevada Power Co.	James McMorran		
1	New York Power Authority	Arnold J. Schuff	Affirmative	
1	Northeast Utilities	David H. Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Kevin M Largura	Negative	
1	NorthWestern Energy	John Canavan	Abstain	
1	Ohio Valley Electric Corp.	Robert Mattey	Negative	View
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Abstain	
1	Omaha Public Power District	Douglas G Peterchuck	Abstain	
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Daryl Hanson		
1	Pacific Gas and Electric Company	Chifong L. Thomas		
1	PacifiCorp	Colt Norrish	Abstain	
1	PECO Energy	Ronald Schloendorn	Affirmative	
1	Platte River Power Authority	John C. Collins	Negative	View

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1	Portland General Electric Co.	Frank F. Afranji	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PowerSouth Energy Cooperative	Larry D. Avery	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Abstain	
1	Progress Energy Carolinas	Sammy Roberts		
1	Public Service Company of New Mexico	Laurie Williams	Abstain	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Public Utility District No. 1 of Chelan County	Chad Bowman	Abstain	
1	Puget Sound Energy, Inc.	Catherine Koch		
1	Rochester Gas and Electric Corp.	John C. Allen	Abstain	
1	Sacramento Municipal Utility District	Tim Kelley	Abstain	
1	Salt River Project	Robert Kondziolka	Negative	
1	San Diego Gas & Electric	Linda Brown		
1	Santee Cooper	Terry L. Blackwell	Abstain	
1	SCE&G	Henry Delk, Jr.	Abstain	
1	Seattle City Light	Pawel Krupa	Abstain	
1	South Texas Electric Cooperative	Richard McLeon	Abstain	
1	Southern California Edison Co.	Dana Cabbell	Affirmative	
1	Southern Company Services, Inc.	Horace Stephen Williamson	Abstain	
1	Southern Illinois Power Coop.	William G. Hutchison	Negative	
1	Southwest Transmission Cooperative, Inc.	James L. Jones	Affirmative	
1	Southwestern Power Administration	Gary W Cox	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tampa Electric Co.	Beth Young		

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1	Tennessee Valley Authority	Larry Akens	Abstain	
1	Tri-State G & T Association, Inc.	Keith V. Carman	Negative	View
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Abstain	
1	Western Area Power Administration	Brandy A Dunn	Negative	
1	Xcel Energy, Inc.	Gregory L Pieper		
2	Alberta Electric System Operator	Mark B Thompson	Abstain	
2	BC Hydro	Venkataramakrishnan Vinnakota	Negative	View
2	California ISO	Gregory Van Pelt	Negative	View
2	Electric Reliability Council of Texas, Inc.	Chuck B Manning		
2	Independent Electricity System Operator	Kim Warren	Negative	View
2	ISO New England, Inc.	Kathleen Goodman		
2	Midwest ISO, Inc.	Jason L Marshall	Negative	View
2	New Brunswick System Operator	Alden Briggs	Affirmative	
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
2	Southwest Power Pool	Charles H Yeung		
3	Alabama Power Company	Richard J. Mandes	Abstain	
3	Allegheny Power	Bob Reeping	Affirmative	
3	Ameren Services	Mark Peters	Affirmative	
3	American Electric Power	Raj Rana		
3	APS	Steven Norris	Abstain	
3	Atlantic City Electric Company	James V. Petrella	Affirmative	

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3	Avista Corp.	Robert Lafferty	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington	Negative	View
3	Blue Ridge Power Agency	Duane S Dahlquist		
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse		
3	City of Clewiston	Lynne Mila	Negative	
3	City of Farmington	Linda R. Jacobson	Abstain	
3	City of Green Cove Springs	Gregg R Griffin	Negative	View
3	City of Leesburg	Phil Janik		
3	Cleco Corporation	Michelle A Corley	Abstain	
3	ComEd	Bruce Krawczyk	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Abstain	
3	Consumers Energy	David A. Lapinski	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Edwin Les Barrow		
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources Services	Michael F Gildea	Abstain	
3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	View
3	East Kentucky Power Coop.	Sally Witt	Affirmative	
3	Entergy	Joel T Plessinger	Affirmative	
3	FirstEnergy Solutions	Kevin Querry	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney		
3	Florida Power & Light Co.	W. R. Schoneck	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	

3	Gainesville Regional Utilities	Kenneth Simmons	Abstain	
3	Georgia Power Company	Anthony L Wilson	Abstain	
3	Georgia System Operations Corporation	R Scott S. Barfield-McGinnis	Affirmative	
3	Great River Energy	Sam Kokkinen	Affirmative	
3	Gulf Power Company	Gwen S Frazier		
3	Hydro One Networks, Inc.	David L Kiguel	Abstain	View
3	JEA	Garry Baker	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke	Abstain	
3	Kissimmee Utility Authority	Gregory David Woessner	Negative	
3	Lakeland Electric	Mace Hunter	Negative	View
3	Lincoln Electric System	Bruce Merrill	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik		
3	Mississippi Power	Don Horsley	Abstain	
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Affirmative	
3	Muscatine Power & Water	John S Bos	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	Marilyn Brown	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone		
3	Northern Indiana Public Service Co.	William SeDoris	Negative	
3	Ocala Electric Utility	David T. Anderson	Affirmative	
3	Orlando Utilities Commission	Ballard Keith Mutters	Abstain	
3	PacifiCorp	John Apperson	Abstain	

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NORTH AMERICAN ELECTRIC
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3	PECO Energy an Exelon Co.	Vincent J. Catania		
3	Platte River Power Authority	Terry L Baker	Negative	View
3	PNM Resources	Michael Mertz	Abstain	
3	Potomac Electric Power Co.	Robert Reuter		
3	Progress Energy Carolinas	Sam Waters	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Public Utility District No. 2 of Grant County	Greg Lange	Negative	View
3	Sacramento Municipal Utility District	James Leigh-Kendall	Abstain	
3	Salt River Project	John T. Underhill	Negative	
3	San Diego Gas & Electric	Scott Peterson		
3	Santee Cooper	Zack Dusenbury	Abstain	
3	Seattle City Light	Dana Wheelock	Abstain	
3	Seminole Electric Cooperative, Inc.	James R Frauen		
3	South Carolina Electric & Gas Co.	Hubert C. Young		
3	Southern California Edison Co.	David Schiada	Affirmative	
3	Tacoma Public Utilities	Travis Metcalfe	Abstain	
3	Tampa Electric Co.	Ronald L Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Negative	View
3	Wisconsin Electric Power Marketing	James R. Keller	Abstain	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	American Municipal Power - Ohio	Kevin Koloini	Abstain	
4	City of Clewiston	Kevin McCarthy	Negative	
4	City of New Smyrna Beach Utilities Commission	Timothy Beyrle	Negative	

4	Consumers Energy	David Frank Ronk	Affirmative	
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Negative	View
4	Fort Pierce Utilities Authority	Thomas W. Richards		
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Abstain	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Negative	View
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen	Abstain	
4	Sacramento Municipal Utility District	Mike Ramirez	Abstain	
4	Seattle City Light	Hao Li	Abstain	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Abstain	
4	Wisconsin Energy Corp.	Anthony Jankowski	Abstain	
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Amerenue	Sam Dwyer	Affirmative	
5	APS	Mel Jensen	Abstain	
5	Avista Corp.	Edward F. Groce	Abstain	
5	BC Hydro and Power Authority	Clement Ma	Negative	View
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Chelan County Public Utility District #1	John Yale		
5	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma	Max Emrick	Abstain	

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

	Power			
5	Cleco Power	Stephanie Huffman		
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Abstain	
5	Consumers Energy	James B Lewis	Affirmative	
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	CPS Energy	Robert B Stevens		
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	Duke Energy	Dale Q Goodwine		
5	East Kentucky Power Coop.	Stephen Ricker	Affirmative	
5	Energy Northwest - Columbia Generating Station	Doug Ramey	Abstain	
5	Entergy Corporation	Stanley M Jaskot	Abstain	
5	Exelon Nuclear	Michael Korchynsky	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Negative	View
5	Great River Energy	Cynthia E Sulzer	Affirmative	
5	Kansas City Power & Light Co.	Scott Heidtbrink	Abstain	
5	Kissimmee Utility Authority	Mike Blough	Abstain	
5	Lakeland Electric	Thomas J Trickey		
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Louisville Gas and Electric Co.	Charlie Martin		
5	Manitoba Hydro	S N Fernando	Affirmative	
5	MEAG Power	Steven Grego	Affirmative	
5	MidAmerican Energy Co.	Christopher Schneider		

5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Gerald Mannarino		
5	Northern Indiana Public Service Co.	Michael K Wilkerson		
5	Omaha Public Power District	Mahmood Z. Safi	Abstain	
5	Orlando Utilities Commission	Richard Kinas		
5	Pacific Gas and Electric Company	Richard J. Padilla		
5	PacifiCorp	Sandra L. Shaffer	Abstain	
5	Portland General Electric Co.	Gary L Tingley	Affirmative	
5	PowerSouth Energy Cooperative	Tim Hattaway	Abstain	
5	PPL Generation LLC	Annette M Bannon	Abstain	
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	
5	PSEG Power LLC	Jerzy A Slusarz	Abstain	
5	RRI Energy	Thomas J. Bradish		
5	Sacramento Municipal Utility District	Bethany Hunter	Abstain	
5	Salt River Project	Glen Reeves	Negative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Abstain	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	South Carolina Electric & Gas Co.	Richard Jones	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Negative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	George T. Ballew	Abstain	
5	Tri-State G & T Association, Inc.	Barry Ingold	Negative	
5	U.S. Army Corps of Engineers Northwestern Division	Karl Bryan		

5	U.S. Bureau of Reclamation	Martin Bauer P.E.	Abstain	
5	Wisconsin Electric Power Co.	Linda Horn		
5	Wisconsin Public Service Corp.	Leonard Rentmeester	Abstain	
5	Xcel Energy, Inc.	Liam Noailles		
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Affirmative	
6	Arizona Public Service Co.	Justin Thompson	Abstain	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Abstain	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Abstain	
6	Constellation Energy Commodities Group	Brenda Powell	Abstain	
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy Carolina	Walter Yeager	Affirmative	
6	Entergy Services, Inc.	Terri F Benoit		
6	Exelon Power Team	Pulin Shah	Affirmative	
6	FirstEnergy Solutions	Mark S Travaglianti	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	View
6	Florida Municipal Power Pool	Thomas E Washburn		
6	Florida Power & Light Co.	Silvia P. Mitchell	Abstain	
6	Great River Energy	Donna Stephenson		
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Abstain	
6	Lakeland Electric	Paul Shipps	Abstain	
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Louisville Gas and Electric Co.	Daryn Barker		

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6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	MidAmerican Energy Co.	Dennis Kimm	Abstain	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	
6	NRG Energy, Inc.	Alan R. Johnson	Abstain	
6	Omaha Public Power District	David Ried	Abstain	
6	PacifiCorp	Scott L Smith	Abstain	
6	Platte River Power Authority	Carol Ballantine	Negative	View
6	Portland General Electric Co.	John Jamieson		
6	PPL EnergyPlus LLC	Mark A Heimbach	Abstain	
6	Progress Energy	John T Sturgeon	Affirmative	
6	PSEG Energy Resources & Trade LLC	James D. Hebson	Abstain	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	RRI Energy	Trent Carlson		
6	Salt River Project	Mike Hummel		
6	Santee Cooper	Suzanne Ritter	Abstain	
6	Seattle City Light	Dennis Sismaet	Abstain	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak		
6	Tacoma Public Utilities	Michael C Hill	Abstain	
6	Tampa Electric Co.	Joann Wehle		
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Western Area Power Administration - UGP Marketing	John Stonebarger		
6	Xcel Energy, Inc.	David F. Lemmons		
8		Roger C Zaklukiewicz	Affirmative	
8		James A Maenner	Abstain	

8		Edward C Stein	Affirmative	
8	JDRJC Associates	Jim D. Cyrulewski	Abstain	
8	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	California Energy Commission	William Mitchell Chamberlain	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Affirmative	
9	North Carolina Utilities Commission	Kimberly J. Jones		
9	Oregon Public Utility Commission	Jerome Murray	Negative	
9	Utah Public Service Commission	Ric Campbell	Affirmative	
10	Florida Reliability Coordinating Council	Linda Campbell	Affirmative	
10	Midwest Reliability Organization	James D Burley	Negative	View
10	New York State Reliability Council	Alan Adamson		
10	Northeast Power Coordinating Council, Inc.	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Negative	View
10	SERC Reliability Corporation	Carter B Edge	Abstain	
10	Southwest Power Pool Regional Entity	Stacy Dochoda	Affirmative	
10	Texas Reliability Entity	Larry D. Grimm	Abstain	
10	Western Electricity Coordinating Council	Louise McCarren	Abstain	

Ballot Results	
Ballot Name:	Project 2010-10: FAC Order 729_in
Ballot Period:	12/30/2010 - 1/8/2011
Ballot Type:	Initial
Total # Votes:	268
Total Ballot Pool:	322
Quorum:	**83.23 % The Quorum has been reached**
Weighted Segment Vote:	58.16 %
Ballot Results:	**The standard will proceed to recirculation ballot.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative		Negative		Abstain	No Vote
			# Votes	Fraction	# Votes	Fraction	# Votes	
1 - Segment 1.	94	1	35	0.593	24	0.407	20	15
2 - Segment 2.	11	1	2	0.2	8	0.8	0	1
3 - Segment 3.	76	1	30	0.588	21	0.412	12	13
4 - Segment 4.	19	1	8	0.571	6	0.429	4	1
5 - Segment 5.	60	1	21	0.618	13	0.382	13	13
6 - Segment 6.	42	1	10	0.476	11	0.524	12	9
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	6	0.3	3	0.3	0	0	3	0
9 - Segment 9.	5	0.3	3	0.3	0	0	1	1
10 - Segment 10.	9	0.7	6	0.6	1	0.1	1	1
Totals	**322**	**7.3**	**118**	**4.246**	**84**	**3.054**	**66**	**54**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Allegheny Power	Rodney Phillips	Affirmative	
1	Ameren Services	Kirit S. Shah	Negative	View
1	American Electric Power	Paul B. Johnson	Affirmative	
1	American Transmission Company, LLC	Jason Shaver		
1	Arizona Public Service Co.	Robert D Smith	Negative	View
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Avista Corp.	Scott Kinney	Abstain	
1	BC Transmission Corporation	Gordon Rawlings	Negative	View

1	Beaches Energy Services	Joseph S. Stonecipher	Negative	View
1	Black Hills Corp	Eric Egge	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Negative	View
1	CenterPoint Energy	Paul Rocha	Abstain	
1	Central Maine Power Company	Brian Conroy		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Negative	View
1	City of Vero Beach	Randall McCamish	Negative	
1	Clark Public Utilities	Jack Stamper	Abstain	
1	Colorado Springs Utilities	Paul Morland	Negative	View
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	View
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	John K Loftis	Abstain	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	E.ON U.S.	Larry Monday		
1	East Kentucky Power Coop.	George S. Carruba	Affirmative	
1	Edison Electric Institute	David Batz	Abstain	
1	Empire District Electric Co.	Ralph Frederick Meyer	Affirmative	
1	Entergy Corporation	George R. Bartlett	Affirmative	
1	FirstEnergy Energy Delivery	Robert Martinko	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Gainesville Regional Utilities	Luther E. Fair	Affirmative	
1	GDS Associates, Inc.	Claudiu Cadar		
1	Georgia Transmission Corporation	Harold Taylor, II	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Robert Solomon	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Negative	View
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Negative	View
1	JEA	Ted E Hobson		
1	Kansas City Power & Light Co.	Michael Gammon	Affirmative	
1	Keys Energy Services	Stan T. Rzad	Negative	View
1	Lake Worth Utilities	Walt Gill	Abstain	
1	Lakeland Electric	Larry E Watt	Negative	View
1	Lee County Electric Cooperative	John W Delucca	Abstain	
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley	Abstain	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	View
1	National Grid	Saurabh Saksena		
1	Nebraska Public Power District	Richard L. Koch	Abstain	
1	Nevada Power Co.	James McMorran		
1	New York Power Authority	Arnold J. Schuff	Affirmative	
1	Northeast Utilities	David H. Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Kevin M Largura	Negative	
1	NorthWestern Energy	John Canavan	Abstain	
1	Ohio Valley Electric Corp.	Robert Mattey	Negative	View
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Abstain	
1	Omaha Public Power District	Douglas G Peterchuck	Abstain	
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Daryl Hanson		
1	Pacific Gas and Electric Company	Chifong L. Thomas		
1	PacifiCorp	Colt Norrish	Affirmative	
1	PECO Energy	Ronald Schloendorn	Affirmative	
1	Platte River Power Authority	John C. Collins	Negative	View
1	Portland General Electric Co.	Frank F. Afranji	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PowerSouth Energy Cooperative	Larry D. Avery	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Abstain	
1	Progress Energy Carolinas	Sammy Roberts	Negative	View
1	Public Service Company of New Mexico	Laurie Williams	Abstain	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Public Utility District No. 1 of Chelan County	Chad Bowman	Abstain	
1	Puget Sound Energy, Inc.	Catherine Koch		
1	Rochester Gas and Electric Corp.	John C. Allen	Abstain	

1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Negative	View
1	San Diego Gas & Electric	Linda Brown		
1	Santee Cooper	Terry L. Blackwell	Abstain	
1	SCE&G	Henry Delk, Jr.	Affirmative	
1	Seattle City Light	Pawel Krupa	Abstain	
1	South Texas Electric Cooperative	Richard McLeon	Abstain	
1	Southern California Edison Co.	Dana Cabbell	Affirmative	
1	Southern Company Services, Inc.	Horace Stephen Williamson	Affirmative	
1	Southern Illinois Power Coop.	William G. Hutchison	Negative	
1	Southwest Transmission Cooperative, Inc.	James L. Jones	Affirmative	
1	Southwestern Power Administration	Gary W Cox	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Larry Akens	Affirmative	
1	Tri-State G & T Association, Inc.	Keith V. Carman	Negative	View
1	Tucson Electric Power Co.	John Tolo	Negative	View
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	View
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Negative	View
1	Xcel Energy, Inc.	Gregory L Pieper	Negative	View
2	Alberta Electric System Operator	Mark B Thompson	Negative	View
2	BC Hydro	Venkataramakrishnan Vinnakota	Negative	View
2	California ISO	Gregory Van Pelt	Negative	View
2	Electric Reliability Council of Texas, Inc.	Chuck B Manning		
2	Independent Electricity System Operator	Kim Warren	Negative	View
2	ISO New England, Inc.	Kathleen Goodman	Negative	View
2	Midwest ISO, Inc.	Jason L Marshall	Negative	View
2	New Brunswick System Operator	Alden Briggs	Affirmative	
2	New York Independent System Operator	Gregory Campoli	Negative	View
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
2	Southwest Power Pool	Charles H Yeung	Negative	View
3	Alabama Power Company	Richard J. Mandes	Affirmative	
3	Allegheny Power	Bob Reeping	Affirmative	
3	Ameren Services	Mark Peters	Negative	
3	American Electric Power	Raj Rana		
3	APS	Steven Norris	Negative	View
3	Atlantic City Electric Company	James V. Petrella	Affirmative	
3	Avista Corp.	Robert Lafferty	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington	Negative	View
3	Blue Ridge Power Agency	Duane S Dahlquist		
3	Bonneville Power Administration	Rebecca Berdahl	Negative	View
3	City of Bartow, Florida	Matt Culverhouse		
3	City of Clewiston	Lynne Mila	Negative	
3	City of Farmington	Linda R. Jacobson	Abstain	
3	City of Green Cove Springs	Gregg R Griffin	Negative	View
3	City of Leesburg	Phil Janik		
3	Cleco Corporation	Michelle A Corley	Abstain	
3	ComEd	Bruce Krawczyk	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	View
3	Consumers Energy	David A. Lapinski	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Edwin Les Barrow		
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources Services	Michael F Gildea	Abstain	
3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	View
3	East Kentucky Power Coop.	Sally Witt	Affirmative	
3	Entergy	Joel T Plessinger	Affirmative	
3	FirstEnergy Solutions	Kevin Querry	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney		
3	Florida Power & Light Co.	W. R. Schoneck	Affirmative	
3	Florida Power Corporation	Lee Schuster	Negative	View
3	Gainesville Regional Utilities	Kenneth Simmons	Abstain	
3	Georgia Power Company	Anthony L Wilson	Affirmative	
3	Georgia System Operations Corporation	R Scott S. Barfield-McGinnis	Affirmative	

3	Great River Energy	Sam Kokkinen	Affirmative	
3	Gulf Power Company	Gwen S Frazier		
3	Hydro One Networks, Inc.	David L Kiguel	Negative	View
3	JEA	Garry Baker	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke	Affirmative	
3	Kissimmee Utility Authority	Gregory David Woessner	Negative	
3	Lakeland Electric	Mace Hunter	Negative	View
3	Lincoln Electric System	Bruce Merrill	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	View
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik		
3	Mississippi Power	Don Horsley	Affirmative	
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Affirmative	
3	Muscatine Power & Water	John S Bos	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	Marilyn Brown	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone		
3	Northern Indiana Public Service Co.	William SeDoris	Negative	
3	Ocala Electric Utility	David T. Anderson	Affirmative	
3	Orlando Utilities Commission	Ballard Keith Mutters	Affirmative	
3	PacifiCorp	John Apperson	Affirmative	
3	PECO Energy an Exelon Co.	Vincent J. Catania		
3	Platte River Power Authority	Terry L Baker	Negative	View
3	PNM Resources	Michael Mertz	Abstain	
3	Potomac Electric Power Co.	Robert Reuter	Affirmative	
3	Progress Energy Carolinas	Sam Waters	Negative	View
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Public Utility District No. 2 of Grant County	Greg Lange	Negative	View
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Negative	View
3	San Diego Gas & Electric	Scott Peterson		
3	Santee Cooper	Zack Dusenbury	Abstain	
3	Seattle City Light	Dana Wheelock	Abstain	
3	Seminole Electric Cooperative, Inc.	James R Frauen		
3	South Carolina Electric & Gas Co.	Hubert C. Young		
3	Southern California Edison Co.	David Schiada	Affirmative	
3	Tacoma Public Utilities	Travis Metcalfe	Negative	View
3	Tampa Electric Co.	Ronald L Donahey	Negative	View
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Negative	View
3	Wisconsin Electric Power Marketing	James R. Keller	Abstain	
3	Xcel Energy, Inc.	Michael Ibold	Negative	View
4	American Municipal Power - Ohio	Kevin Koloini	Abstain	
4	City of Clewiston	Kevin McCarthy	Negative	
4	City of New Smyrna Beach Utilities Commission	Timothy Beyrle	Negative	
4	Consumers Energy	David Frank Ronk	Affirmative	
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Negative	View
4	Fort Pierce Utilities Authority	Thomas W. Richards	Negative	View
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Abstain	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Negative	View
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Abstain	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Negative	View
4	Wisconsin Energy Corp.	Anthony Jankowski	Abstain	
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Amerenue	Sam Dwyer	Negative	
5	APS	Mel Jensen	Negative	View
5	Avista Corp.	Edward F. Groce	Abstain	

5	BC Hydro and Power Authority	Clement Ma	Negative	View
5	Bonneville Power Administration	Francis J. Halpin	Negative	View
5	Chelan County Public Utility District #1	John Yale		
5	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Max Emrick	Negative	View
5	Cleco Power	Stephanie Huffman		
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Negative	View
5	Consumers Energy	James B Lewis	Affirmative	
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	CPS Energy	Robert B Stevens		
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	Duke Energy	Dale Q Goodwine		
5	East Kentucky Power Coop.	Stephen Ricker	Affirmative	
5	Energy Northwest - Columbia Generating Station	Doug Ramey	Affirmative	
5	Entergy Corporation	Stanley M Jaskot	Affirmative	
5	Exelon Nuclear	Michael Korchynsky	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Negative	View
5	Great River Energy	Cynthia E Sulzer	Affirmative	
5	Kansas City Power & Light Co.	Scott Heidtbrink	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Negative	
5	Lakeland Electric	Thomas J Trickey		
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Louisville Gas and Electric Co.	Charlie Martin		
5	Manitoba Hydro	S N Fernando	Affirmative	
5	MEAG Power	Steven Grego	Affirmative	
5	MidAmerican Energy Co.	Christopher Schneider		
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Gerald Mannarino		
5	Northern Indiana Public Service Co.	Michael K Wilkerson		
5	Omaha Public Power District	Mahmood Z. Safi	Abstain	
5	Orlando Utilities Commission	Richard Kinas	Affirmative	
5	Pacific Gas and Electric Company	Richard J. Padilla		
5	PacifiCorp	Sandra L. Shaffer	Affirmative	
5	Portland General Electric Co.	Gary L Tingley	Affirmative	
5	PowerSouth Energy Cooperative	Tim Hattaway	Abstain	
5	PPL Generation LLC	Annette M Bannon	Abstain	
5	Progress Energy Carolinas	Wayne Lewis	Negative	View
5	PSEG Power LLC	Jerzy A Slusarz	Abstain	
5	RRI Energy	Thomas J. Bradish		
5	Sacramento Municipal Utility District	Bethany Hunter	Affirmative	
5	Salt River Project	Glen Reeves	Negative	View
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Abstain	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	South Carolina Electric & Gas Co.	Richard Jones	Affirmative	
5	South Mississippi Electric Power Association	Jerry W Johnson		
5	Tampa Electric Co.	RJames Rocha	Negative	
5	Tenaska, Inc.	Scott M. Helyer	Affirmative	
5	Tennessee Valley Authority	George T. Ballew	Affirmative	
5	Tri-State G & T Association, Inc.	Barry Ingold	Negative	
5	U.S. Army Corps of Engineers Northwestern Division	Karl Bryan		
5	U.S. Bureau of Reclamation	Martin Bauer P.E.	Abstain	
5	Wisconsin Electric Power Co.	Linda Horn	Abstain	
5	Wisconsin Public Service Corp.	Leonard Rentmeester	Abstain	
5	Xcel Energy, Inc.	Liam Noailles	Negative	View
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Negative	View
6	Arizona Public Service Co.	Justin Thompson	Negative	View
6	Bonneville Power Administration	Brenda S. Anderson	Negative	
6	Cleco Power LLC	Robert Hirchak	Abstain	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Negative	View
6	Constellation Energy Commodities Group	Brenda Powell	Abstain	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy Carolina	Walter Yeager	Affirmative	

6	Entergy Services, Inc.	Terri F Benoit		
6	Exelon Power Team	Pulin Shah	Affirmative	
6	FirstEnergy Solutions	Mark S Travaglianti	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	View
6	Florida Municipal Power Pool	Thomas E Washburn		
6	Florida Power & Light Co.	Silvia P. Mitchell	Abstain	
6	Great River Energy	Donna Stephenson		
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Negative	View
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Louisville Gas and Electric Co.	Daryn Barker		
6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	MidAmerican Energy Co.	Dennis Kimm	Abstain	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	
6	NRG Energy, Inc.	Alan R. Johnson	Abstain	
6	Omaha Public Power District	David Ried	Abstain	
6	PacifiCorp	Scott L Smith	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Negative	View
6	Portland General Electric Co.	John Jamieson		
6	PPL EnergyPlus LLC	Mark A Heimbach	Abstain	
6	Progress Energy	John T Sturgeon	Negative	
6	PSEG Energy Resources & Trade LLC	James D. Hebson	Abstain	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	RRI Energy	Trent Carlson		
6	Salt River Project	Mike Hummel		
6	Santee Cooper	Suzanne Ritter	Abstain	
6	Seattle City Light	Dennis Sismaet	Abstain	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Negative	View
6	Tampa Electric Co.	Joann Wehle		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Western Area Power Administration - UGP Marketing	John Stonebarger		
6	Xcel Energy, Inc.	David F. Lemmons	Negative	View
8		James A Maenner	Abstain	
8		Roger C Zaklukiewicz	Affirmative	
8		Edward C Stein	Affirmative	
8	JDRJC Associates	Jim D. Cyrulewski	Abstain	
8	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	California Energy Commission	William Mitchell Chamberlain	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Affirmative	
9	North Carolina Utilities Commission	Kimberly J. Jones		
9	Oregon Public Utility Commission	Jerome Murray	Abstain	
9	Utah Public Service Commission	Ric Campbell	Affirmative	
10	Florida Reliability Coordinating Council	Linda Campbell	Affirmative	
10	Midwest Reliability Organization	James D Burley	Negative	View
10	New York State Reliability Council	Alan Adamson		
10	Northeast Power Coordinating Council, Inc.	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Carter B Edge	Affirmative	
10	Southwest Power Pool Regional Entity	Stacy Dochoda	Affirmative	
10	Texas Reliability Entity	Larry D. Grimm	Abstain	
10	Western Electricity Coordinating Council	Louise McCarren	Affirmative	View

Standards Announcement
Successive Ballot Results
Project 2010-10: FAC Order 729

Now available at: https://standards.nerc.net/Ballots.aspx

Successive Ballot and Non-binding Poll Results for FAC-013-2 – Assessment of Transfer Capability for the Near-Term Transmission Planning Horizon

A successive ballot for the proposed standard, FAC-013-2 – Assessment of Transfer Capability for the Near-Term Transmission Planning Horizon, ended on January 8, 2011. A non-binding poll of the proposed Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) also ended on January 8, 2011. Voting and poll statistics are listed below, and the Ballot Results Web page provides a link to the detailed results.

Ballot for Standard:

- Quorum: 83.23 %
- Approval: 58.16%

Non-binding Poll for VRFs and VSLs:

- Quorum: 79.50 %
- Supportive Opinion: 68.84%

Next Steps

The drafting team will consider all comments (those submitted with a comment form, and those submitted with a ballot or with the non-binding poll) and will determine whether to make additional changes to the standard and its implementation plan.

Project Background

The proposed standard addresses FERC directives from FERC Order 729 as well as stakeholder comments received during an initial formal comment period and ballot. In Order 729, FERC ruled that the ATC standards developed in Project 2006-07 did not completely address the topics covered in FAC-012 and -013 and did not fully address the associated directives from Order 693. Accordingly, FERC denied the portions of the implementation plan that would have retired these standards, and instead directed NERC to use the standards development process to make changes to the FAC standards and file those changes with FERC no later than 60 days prior to the effective date of the standards, which is April 1, 2011 (requiring the proposed changes to be filed on or before January 28, 2011).

More information can be found on the project page:
http://www.nerc.com/filez/standards/Project2010-10_FAC_Order_729.html

Ballot Criteria

Approval requires both (1) a quorum, which is established by at least 75% of the members of the ballot pool submitting either an affirmative vote, a negative vote, or an abstention, and (2) 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.

Non-binding polls of VRFs and VSLs are conducted to provide the drafting team with constructive feedback on proposed VRFs and VSLs and also to provide information to assist in developing a recommendation for Board of Trustees approval.

Standards Development Process

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

For more information or assistance, please contact Monica Benson,
Standards Process Administrator, at monica.benson@nerc.net or at 609.452.8060.

North American Electric Reliability Corporation
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NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments on FAC-013-2 — Planning Transfer Capability — Project 2010-10

The FAC-013-2 — Planning Transfer Capability Drafting Team thanks all commenters who submitted comments on the proposed SAR and modifications proposed FAC-013-2 — Planning Transfer Capability (Project 2010-10). These standards were posted for a 30-day public comment period from December 10, 2010 through January 8, 2011. The stakeholders were asked to provide feedback on the standards through a special Electronic Comment Form. There were 28 sets of comments, including comments from more than 80 different people from approximately 45 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.
The comments may be reviewed in their original format on the following page:

http://www.nerc.com/filez/standards/Project2010-10_FAC_Order_729.html

Based on stakeholder comments, the following changes were made to the standard:

- The proposed definition of Year One was moved from project 2006-02 – Assess Transmission and Future Needs to this project as the term "Year One" is used in the proposed definition of "Near-Term Transmission Planning Horizon."
- The Purpose statement was revised to better align with the intent of the requirements
- The qualifying phrase, 'long-term' was added to clarify the intent of the scope of planned outages that must be addressed in the Planning Transfer methodology.
- Requirement R2, Part 2.2 was confusing as it linked the request for assessment results and with the distribution of the methodology. The team clarified that the intent of Part 2.2 is related to distribution of the methodology, and added a sentence to Requirement R5 to clarify that the results must be provided to entities that request the results and have a reliability-related need for the information. A sentence was added to clarify that entities do not have to share information that is confidential.
- The VSLs for R1 were clarified, and an error in the VSLs for R2 was corrected.
- The team removed capitalization from the word, "methodology" as this is not a defined term.

Minority Issues:

- Some entities indicated that they disagree with the need for the standard. FERC Order 729 addressed the need for the standard and determined in paragraph 290 that the assessment of transfer capability "will be useful for long-term planning, in general, by measuring sufficient long-term capacity needed to ensure the reliable operation of the Bulk-Power System." The standard drafting team is charged with addressing FERC's directives to the ERO and has sought to find an equally effective and efficient means to meet FERC's directive - while maximizing the benefit to reliable transmission system planning. The applicability was assigned to the Planning Coordinator because of their generally wider area view and to be in accord with a FERC directive.
- Some entities indicated that WECC has requirements that address the same issue as FAC-013-2 or that the requirements in FAC-013-2 duplicate those in other standards. The SDT recognizes that FAC-013-2 may use the same study work that is used in MOD-029-1; that would not be true for entities that use MOD-028-1 and MOD-030-2. Regardless, the methodologies in the MOD standards DO have a defined date range (the Operations Planning horizon). FAC-013-2 has a different date range (the Near-Term Planning Horizon). Therefore the standards are not duplicative for WECC and definitively not duplicative for non-WECC entities; even if some of the study work is

the same study work that is used in MOD-029-1. FAC-013-2 has been written to provide flexibility to the Planning Coordinator to perform the assessment according to their knowledge of the behavior and needs of their system. The MOD Standards do not afford such flexibility.

- Some entities indicated that the requirements in FAC-013 belong in the TPL standards and the SDT indicated that, in the future, the requirements may be moved.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Herb Schrayshuen, at 609-452-8060 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

	Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X

Additional Member	Additional Organization	Region	Segment Selection	
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Gregory Campoli	New York Independent System Operator	NPCC	2
3.	Kurtis Chong	Independent Electricity System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Dean Ellis	Dynegy Generation	NPCC	5
8.	Brian Evans-Mongeon	Utility Services	NPCC	8
9.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
10.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5
11.	Kathleen Goodman	ISO - New England	NPCC	2
12.	Chantel Haswell	FPL Group, Inc.	NPCC	5
13.	David Kiguel	Hydro One Networks Inc.	NPCC	1

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

14.	Michael R. Lombardi	Northeast Utilities	NPCC	1
15.	Randy MacDonald	New Brunswick System Operator	NPCC	2
16.	Bruce Metruck	New York Power Authority	NPCC	6
17.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
18.	Robert Pellegrini	The United Illuminating Company	NPCC	1
19.	Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
20.	Saurabh Saksena	National Grid	NPCC	1
21.	Michael Schiavone	National Grid	NPCC	1
22.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

				1	2	3	4	5	6	7	8	9	10
2.	Group	Frank Gaffney	Florida Municipal Power Agency	X		X	X	X	X	X			

Additional Member	Additional Organization	Region	Segment Selection	
1.	Tim Beyrle	Utilities Commission,City of New Smyrna Beach	FRCC	4
2.	Greg Woessner	Kissimmee Utility Authority	FRCC	3
3.	Jim Howard	Lakeland Electric	FRCC	3
4.	Lynne Mila	City of Clewiston	FRCC	3
5.	Joe Stonecipher	Beaches Energy Services	FRCC	1
6.	Cairo Vanegas	Fort Pierce Utility Authority	FRCC	4
7.	Randy Hahn	Ocala Electric Utility	FRCC	3

				1	2	3	4	5	6	7	8	9	10
3.	Group	Charles W. Long	SERC Planning Standards Subcommittee	X									X

Additional Member	Additional Organization	Region	Segment Selection	
1.	Pat Huntley	SERC Reliability Corporation	SERC	10
2.	Bob Jones	Southern Company Services	SERC	1
3.	Darrin Church	Tennessee Valley Authority	SERC	1
4.	Jim Kelley	PowerSouth Energy Cooperative	SERC	1
5.	John Sullivan	Ameren Services Company	SERC	1

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

6.	Phil Kleckley	South Carolina Electric & Gas Co.	SERC	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4.	Group	Denise Koehn	Bonneville Power Administration	X		X		X	X				

Additional Member		Additional Organization	Region	Segment Selection
1.	Kyle Kohne	BPA, Transmission Planning	WECC	1
2.	James Randall	BPA, Transmission Planning	WECC	1
3.	Tony Radcliff	BPA, Transmission Planning	WECC	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5.	Group	Carol Gerou	MRO's NERC Standards Review Subcommittee										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mahmood Safi	Omaha Public Utility District	MRO	1, 3, 5, 6, 10
2.	Chuck Lawrence	American Transmission Company	MRO	1
3.	Tom Webb	Wisconsin Public Service Corporation	MRO	3, 4, 5, 6
4.	Jason Marshall	Midwest ISO Inc.	MRO	2
5.	Jodi Jenson	Western Area Power Administration	MRO	1, 6
6.	Ken Goldsmith	Alliant Energy	MRO	4
7.	Alice Ireland	Xcel Energy	MRO	1, 3, 5, 6
8.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
9.	Eric Ruskamp	Lincoln Electric System	MRO	1, 3, 5, 6
10.	Joseph Knight	Great River Energy	MRO	1, 3, 5, 6
11.	Joe DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6
12.	Scott Nickels	Rochester Public Utilties	MRO	4
13.	Terry Harbour	MidAmerican Energy Company	MRO	1, 3, 5, 6
14.	Richard Burt	Minnkota Power Cooperative, Inc.	MRO	1, 3, 5, 6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Group	Al DiCaprio	IRC Standards Review Committee		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Bill Phillips	Midwest ISO	MRO	2

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

2. Patrick Brown	PJM	RFC	2
3. Jim Castle	NYISO	NPCC	2
4. Greg Van Pelt	CAISO	WECC	2
5. Charles Yeung	SPP	SPP	2
6. Steve Myers	ERCOT	ERCOT	2
7. Mark Thompson	AESO	WECC	2
8. Ben Li	IESO	NPCC	2
9. Matt Goldberg	ISO-NE	NPCC	2

				1	2	3	4	5	6	7	8	9	10
7.	Individual	Sandra Shaffer	PacifiCorp	X		X		X	X				
8.	Individual	Janet Smith	Arizona Public Service Company	X		X		X	X				
9.	Individual	Steve Rueckert	Western Electricity Coordinating Council										X
10.	Individual	Ross Kovacs	Georgia Transmission Corporation	X									
11.	Individual	Joe Petaski	Manitoba Hydro	X		X		X	X				
12.	Individual	Jonathan Appelbaum	United Illuminating Co.	X									
13.	Individual	Kathleen Goodman	ISO New England, Inc.		X								
14.	Individual	Aaron Staley	Orlando Utilities Commission	X									
15.	Individual	Thad Ness	American Electric Power	X		X		X	X				
16.	Individual	Kirit Shah	Ameren	X		X		X	X				
17.	Individual	Greg Rowland	Duke Energy	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
18.	Individual	Chris de Graffenried	Consolidated Edison Co. of NY, Inc.	X		X		X	X				
19.	Individual	Bill Middaugh	Tri-State Generation & Transmission Assn., Inc.	X	X								
20.	Individual	JC Culberson	ERCOT										
21.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
22.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				
23.	Individual	Gregory Campoli	New York Independent System Operator		X								
24.	Individual	Andrew Z. Pusztai	American Transmission Company	X									
25.	Individual	John Tolo	Tucson Electric Power	X									
26.	Individual	Dan Rochester	Independent Electricity System Operator		X								
27.	Individual	Janelle Marriott	Tri-State Generation and Transmission Assn., Inc.	X		X		X					
28.	Individual	Dennis Chastain	Tennessee Valley Authority	X		X		X	X				

1. The SDT has defined the term Near-Term Transmission Planning Horizon. The definition reads "The transmission planning period that covers year's one through five." (This definition was originally developed by the Assess Transmission Future Needs SDT and has been moved to this project as this project will be completed before the Assess Transmission Future Needs project.) Do you agree that this term provides clarity as to the period the standard applies?

Summary Consideration: While most commenters indicated that the proposed definition did add clarity, some indicated that the definition includes a draft defined term, "Year One" and asked that the defined term, "Year One" be added to this project and this was done. Adoption of both the Near-Term Transmission Planning Horizon definition and the Year One definition from the TPL-001-2 standard development project will clearly define the assessment period addressed in FAC-013-2.

Near-Term Transmission Planning Horizon: The transmission planning period that covers years one through five.

Year One: The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For the Planning Assessment started in a given calendar year, Year One includes the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One includes the forecasted peak Load period for either 2012 or 2013.

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 1 Comment</th></tr>
<tr><td>Florida Municipal Power Agency</td><td>No</td><td>Is year one the current year or the next year, e.g., doing a study in 2011, is year one 2011 or 2012?</td></tr>
<tr><td colspan="3">Response: The definition of Year One from the draft TPL-001-2 standard, which is used in the Near-Term Transmission Planning Horizon definition, will also be adopted in this standard which clarifies the assessment period.</td></tr>
<tr><td>Ameren</td><td>No</td><td>As one of the benefits of transfer capability testing and analysis is tracking/trending, does a definition also need to be developed for Long-Term Transmission Planning Horizon? This would allow comparison of transfer capabilities in the near-term as well as long-term planning horizons.</td></tr>
<tr><td colspan="3">Response: The standard is not intended to require assessment of Transfer Capability beyond the Near-Term Transmission Planning Horizon. Therefore the Long-Term Transmission Planning Horizon definition is not required.</td></tr>
<tr><td>Northeast Power Coordinating Council</td><td>No</td><td rowspan="2">The definition is not clear as to when year one starts. Suggest rewording to: "The transmission planning period that covers the period of 12 to 60 months from the date of the assessment."</td></tr>
<tr><td>Consolidated Edison Co. of NY,</td><td>No</td></tr>
</table>

Organization	Yes or No	Question 1 Comment
Inc.		
New York Independent System Operator	No	
ISO New England, Inc.	No	
Response: The definition of Year One from the TPL-001-2 standard, which is used in the Near-Term Transmission Planning Horizon definition, will also be adopted in this standard which clarifies the assessment period.		
IRC Standards Review Committee	**No**	**There still is some confusion regarding when year one starts. We assume that year one is intended to start at 12 months. If this is the case, the definition should be made clear that years one through five cover the time frame from 12 to 60 months.**
Response: The definition of Year One from the TPL-001-2 standard, which is used in the Near-Term Transmission Planning Horizon definition, will also be adopted in this standard which clarifies the assessment period.		
Tucson Electric Power	No	Previously there was an Operating Horizon (Year 1) and a Planning Horizon (Year 2 through 10). would there then be an overlap with the Operating Horizon (Year1) and the first year of the Near-Term Transmission Planning Horizon. What is the distinction between the Near-Term and Long-Term Planning Horison?
Response: There are other terms utilized in the standards process that delineate time frames. The only one relevant to the FAC-013-2 standard is the Near-Term Transmission Planning Horizon. Some overlap with other terms should not be a problem. TPL-001-2 introduces the Long-Term Transmission Planning Horizon definition and provides a clear distinction from the Near-Term Transmission Planning Horizon.		
Bonneville Power Administration	Yes	The term provides clarity to the time period the standard applies to. However, the Near-Term Transmission Planning Horizon is already defined in the TPL-001 R1.2.
Response: The FAC-013 standard will be approved before TPL-001-2 and will be used to introduce the new Near-Term Transmission Planning definition and Year One definition.		
Western Electricity Coordinating Council	Yes	Procedurally, if this definition is approved in FAC-013-2 before TPL-001-1 is finalized, will the definition be removed from the TPL-001-1 section of new terms since it will already be an approved term?
Response: Yes		

Organization	Yes or No	Question 1 Comment
Duke Energy	Yes	However adoption of the Near-Term Transmission Planning Horizon definition from the TPL-001-2 standard development will also require adoption of the definition of Year One which is part of the Near-Term Transmission Planning Horizon definition.
Response: The definition of Year One from the TPL-001-2 standard, which is used in the Near-Term Transmission Planning Horizon definition, will also be adopted in this standard which clarifies the assessment period.		
SERC Planning Standards Subcommittee	Yes	
MRO's NERC Standards Review Subcommittee	Yes	
PacifiCorp	Yes	
Arizona Public Service Company	Yes	
Georgia Transmission Corporation	Yes	
Manitoba Hydro	Yes	
United Illuminating Co.	Yes	
Orlando Utilities Commission	Yes	
American Electric Power	Yes	
Tri-State Generation & Transmission Assn., Inc.	Yes	
ERCOT	Yes	
South Carolina Electric and Gas	Yes	

Organization	Yes or No	Question 1 Comment
Xcel Energy	Yes	
American Transmission Company	Yes	
Independent Electricity System Operator	Yes	
Tri-State Generation and Transmission Assn., Inc.	Yes	
Tennessee Valley Authority	Yes	

2. The SDT has modified the Purpose statement. The Purpose statement now reads "To ensure that Planning Coordinators have a methodology for, and perform an annual assessment of the ability to transfer energy (in the Near-Term Transmission Planning Horizon) to identify potential future weaknesses and limiting Facilities that could impact the reliability of the Bulk Electric System (BES)." Do you agree that the revised Purpose statement provides greater clarity as to what the standard is intended to accomplish?

Summary Considerations: While many commenters agreed with the revised purpose statement, several commenters recommended a modification to better align the purpose with the requirements. To further align the purpose statement with the content of the standard, it has been revised to "To ensure that Planning Coordinators have a methodology for, and perform an annual assessment to identify potential future Transmission System weaknesses and limiting facilities that could impact the Bulk Electric System's (BES) ability to reliably transfer energy in the Near-Term Transmission Planning Horizon."

Several comments indicate that the standard is either duplicative or unnecessary for reliable planning. FERC Order 729 addressed these issues and determined in paragraph 290 that the assessment of transfer capability "will be useful for long-term planning, in general, by measuring sufficient long-term capacity needed to ensure the reliable operation of the Bulk-Power System." The standard drafting team is charged with addressing FERC's directives to the ERO and has sought to find an equally effective and efficient means to meet FERC's directive - while maximizing the benefit to reliable transmission system planning.

Some commenters indicated that, as written, R4 could possibly allow the Planning Coordinator to conduct an assessment based on a simulation that has not been updated. The intent is to require a simulation to be performed each calendar year and assessment conducted based on that simulation. To clarify this intent, R4 has been reworded as follows: "During each calendar year, each Planning Coordinator shall conduct simulations and document an assessment based on those simulations in accordance with its transfer capability methodology for at least one year in the Near-Term Transmission Planning Horizon."

Organization	Yes or No	Question 2 Comment
ISO New England, Inc.		The statement adds clarity; however the revised standard does not serve this purpose. Knowing the transfer limit does not assess the reliability of the BES. The TPLs are the standards which will determine BES reliability through demonstration of system's ability to serve load through the capability of the transmission system and internal resources.
Response: The purpose of the standard is to focus more on the limiting facilities that are identified under the stress of specific energy transfers rather than the specific values. Changes in energy transfers can occur for a variety of reasons (change in resource plans, changes in energy costs, new generation sources,..) and understanding the potential impact on facilities, (and thus reliability), is important to effective transmission planning. The SDT does not disagree that it may be appropriate to move the requirements of FAC-013-2 into the TPL standards at some time in the future.		

Organization	Yes or No	Question 2 Comment
FERC Order 729 addressed the need for the standard and determined in paragraph 290 that the assessment of transfer capability "will be useful for long-term planning, in general, by measuring sufficient long-term capacity needed to ensure the reliable operation of the Bulk-Power System." The standard drafting team is charged with addressing FERC's directives to the ERO and has sought to find an equally effective and efficient means to meet FERC's directive - while maximizing the benefit to reliable transmission system planning.		
Northeast Power Coordinating Council	No	The statement adds clarity; however the revised standard does not serve this purpose. Knowing the transfer limit does not assess the reliability of the BES. The Transmission Planning Standards (TPL) are the standards which will determine BES reliability by demonstrating a system's ability to serve load through the capability of the transmission system and internal resources.
Consolidated Edison Co. of NY, Inc.	No	
Response: The purpose of the standard is to focus more on the limiting facilities that are identified under the stress of specific energy transfers, rather than the specific values. Changes in energy transfers can occur for a variety of reasons (change in resource plans, changes in energy costs, new generation sources,..) and understanding the potential impact on facilities, (and thus reliability), is important to effective transmission planning. The SDT does not disagree that it may be appropriate to move the requirements of FAC-013-2 into the TPL standards at some time in the future. FERC Order 729 addressed the need for the standard and determined in paragraph 290 that the assessment of transfer capability "will be useful for long-term planning, in general, by measuring sufficient long-term capacity needed to ensure the reliable operation of the Bulk-Power System." The standard drafting team is charged with addressing FERC's directives to the ERO and has sought to find an equally effective and efficient means to meet FERC's directive - while maximizing the benefit to reliable transmission system planning.		
New York Independent System Operator	No	The statement adds clarity; however the revised standard does not serve this purpose. Knowing the transfer limit does not assess the reliability of the BES. The TPLs are the standards which will determine BES reliability through demonstration of system's ability to serve load through the capability of the transmission system and internal resources. There are no TPL standards that require system expansion for maintenance of transfer capabilities above firm transfer commitments, therefore transfer capabilities in the planning horizon provide no additional information that can be used for reliability planning.
Response: The purpose of the standard is to focus more on the limiting facilities that are identified under the stress of specific energy transfers, rather than the specific values. Changes in energy transfers can occur for a variety of reasons (change in resource plans, changes in energy costs, new generation sources,..) and understanding the potential impact on facilities, (and thus reliability), is important to effective transmission planning. The SDT does not disagree that it may be appropriate to move the requirements of FAC-013-2 into the TPL standards at some time in the future. FERC Order 729 addressed the need for the standard and determined in paragraph 290 that the assessment of transfer capability "will be useful for long-term planning, in general, by measuring sufficient long-term capacity needed to ensure the reliable operation of the Bulk-Power System." The standard drafting team is charged with addressing FERC's directives to the ERO and has sought to find an equally effective and efficient means to meet FERC's directive - while maximizing the		

Organization	Yes or No	Question 2 Comment
benefit to reliable transmission system planning.		
Bonneville Power Administration	No	BPA is still recommending a "no" vote because of the conflict between the purpose statement and the title of the standard, as well as the concern regarding the potential for double jeopardy given our belief that the requirements of the proposed FAC-013-2 are duplicative with other standards. BPA believes it would be more appropriate to incorporate the annual assessment and reporting time-line requirements stated in the proposed standard into the appropriate section of FAC-010, FAC-014, and the TPL Planning Standards. If this assessment is for reliability, it will be conducted using power flow stability programs, etc. These programs do not assess anything based on "energy". Perhaps it should be "power" instead. The condition that the development of the transfer capabilities (as requested by the RRO or Regional Entity) was deleted from this version. We understand that the SDT tries to codify what would be done; however, it will still require that an annual assessment be done. Theoretically, we can use the Assessment Studies required in the TPL standards. As written, we are not certain that we can use FAC-010-2 and FAC-014-2 results to comply with this proposed FAC-013-2. Additionally, why is Applicability applied to Planning Coordinators and not the Transmission Planner?
Response: The SDT is not certain of the conflict BPA notes but the Purpose has been modified to better align with the content of the standard. FAC-013-2 has been written to provide flexibility to the Planning Coordinator to perform the assessment according to their knowledge of the behavior and needs of their system. FAC-010-2 and FAC-014-2 do not afford such flexibility. The applicability was assigned to the Planning Coordinator because of their generally wider area view and to be in accord with a FERC directive. The SDT recognizes that FAC-013-2 may use some of WECC's required efforts in FAC-010, FAC-014, and the TPL Planning Standards TPL-001 through TPL-004; that would not necessarily be true for entities outside of WECC. With regard to double jeopardy, the methodology in FAC-013-2 has a different date range (the Near-Term Planning Horizon). Therefore the standards are not completely duplicative for WECC and definitively not duplicative for non-WECC entities; even if some of the effort is the same work that is used in other standards.		
MRO's NERC Standards Review Subcommittee	No	The existing Reliability Standards that apply for the Near-Term Planning Horizon (e.g. TPLs) require the identification of potential future weaknesses and limiting Facilities that could impact reliability of the BES for firm transfer commitments, not transfer capabilities beyond the firm transfer commitments. The assessment of transfer capabilities beyond the firm transfer commitments in the Near-Term Planning Horizon would identify economic non-transfer opportunities that exist with the future planned transmission system and possible system expansion or improvements that could increase economic non-firm transfer opportunities. Therefore, this purpose is appropriate for an open access, economic type of standard, not a transmission system Reliability Standard.
American Transmission Company	No	

Organization	Yes or No	Question 2 Comment
		The purpose statement should assign the applicability of this standard to the Transmission Service Provider function and not the Planning Coordinator since this standard deals with identifying non-firm transfer capabilities. Therefore, the applicability should be changed from Planning Coordinator to Transmission Service Provider throughout this standard. Otherwise, perhaps the FAC-013-2 standard should be converted to an appropriate open access, economic (e.g. NAESB) standard.
Response: The purpose of the standard is to focus more on the limiting facilities that are identified under the stress of specific energy transfers, rather than the specific values. Changes in energy transfers can occur for a variety of reasons (change in resource plans, changes in energy costs, new generation sources,..) and understanding the potential impact on facilities, (and thus reliability), is important to effective transmission planning. The SDT does not disagree that it may be appropriate to move the requirements of FAC-013-2 into the TPL standards at some time in the future. FERC Order 729 addressed the need for the standard and determined in paragraph 290 that the assessment of transfer capability “will be useful for long-term planning, in general, by measuring sufficient long-term capacity needed to ensure the reliable operation of the Bulk-Power System.” The standard drafting team is charged with addressing FERC’s directives to the ERO and has sought to find an equally effective and efficient means to meet FERC’s directive - while maximizing the benefit to reliable transmission system planning. The applicability was assigned to the Planning Coordinator because of their generally wider area view and to be in accord with a FERC directive.		
IRC Standards Review Committee	No	While the standard represents an improvement by allowing the transfer capability to be calculated in year 1 and not years 2-5, we still generally disagree with the purpose. Transfer capabilities in the planning horizon are not useful for the reliable planning of the transmission system and/or any expansion plans. The current, approved TPL standards already provide system expansion requirements to assure reliable system performance with regard to firm transfer commitments, but not to limits that may exceed those firm commitments such as those that would be indicated in PTC calculations. Further, it must be noted that there are no TPL standards that require system expansion for maintenance of transfer capabilities above firm transfer commitments. As such, transfer capabilities in the planning horizon provide no additional information that can be used for system planning. In addition, transfer capabilities calculated 2 to 5 years ahead are not useful to give system operators advance warning or appropriate, applicable operating limits because operating horizon conditions will be significantly different than those projected during the planning horizon (2 to 5 years previously). IESO does not support the response to this question.
Response: The purpose of the standard is to focus more on the limiting facilities that are identified under the stress of specific energy transfers, rather than the specific values. Changes in energy transfers can occur for a variety of reasons (change in resource plans, changes in energy costs, new generation sources,..) and understanding the potential impact on facilities, (and thus reliability), is important to effective transmission planning. The SDT does not disagree that it may be appropriate to move the requirements of FAC-013-2 into the TPL standards at some time in the future.		

Organization	Yes or No	Question 2 Comment
FERC Order 729 addressed the need for the standard and determined in paragraph 290 that the assessment of transfer capability "will be useful for long-term planning, in general, by measuring sufficient long-term capacity needed to ensure the reliable operation of the Bulk-Power System." The standard drafting team is charged with addressing FERC's directives to the ERO and has sought to find an equally effective and efficient means to meet FERC's directive - while maximizing the benefit to reliable transmission system planning.		
ERCOT	No	Transfer capabilities in the planning horizon are not useful for the reliable planning of the transmission system and/or any expansion plans. The current, approved TPL standards already provide system expansion requirements to assure reliable system performance with regard to firm transfer commitments, but not to limits that may exceed those firm commitments such as those that would be indicated in PTC calculations. Further, it must be noted that there are no TPL standards that require system expansion for maintenance of transfer capabilities above firm transfer commitments. As such, transfer capabilities in the planning horizon provide no additional information that can be used for system planning. In addition, transfer capabilities calculated 2 to 5 years ahead are not useful to give system operators advance warning or appropriate, applicable operating limits because operating horizon conditions will be significantly different than those projected during the planning horizon (2 to 5 years previously).
Response: The purpose of the standard is to focus more on the limiting facilities that are identified under the stress of specific energy transfers rather than the specific values. Changes in energy transfers can occur for a variety of reasons (change in resource plans, changes in energy costs, new generation sources,..) and understanding the potential impact on facilities, (and thus reliability), is important to effective transmission planning. The SDT does not disagree that it may be appropriate to move the requirements of FAC-013-2 into the TPL standards at some time in the future. FERC Order 729 addressed the need for the standard and determined in paragraph 290 that the assessment of transfer capability "will be useful for long-term planning, in general, by measuring sufficient long-term capacity needed to ensure the reliable operation of the Bulk-Power System." The standard drafting team is charged with addressing FERC's directives to the ERO and has sought to find an equally effective and efficient means to meet FERC's directive - while maximizing the benefit to reliable transmission system planning.		
Arizona Public Service Company	No	It is not clear if an entity would have to perform yearly TTC studies for all paths or whether an entity could access each path yearly and determine if a need existed for a restudy of the TTC for a particular path.
Response: As written, R4 could possibly allow the Planning Coordinator to conduct an assessment based on a simulation that has not been updated. The intent is to require a simulation to be performed each calendar year and assessment conducted based on that simulation. To clarify this intent, R4 has been reworded as follows: "During each calendar year, each Planning Coordinator shall conduct simulations and document an assessment based on those simulations in accordance with its transfer capability methodology for at least one year in the Near-Term Transmission Planning Horizon."		
Western Electricity Coordinating Council		The current title is Assessment of Transfer Capability..., but the Purpose statement identifies that the purpose is to perform and annual assessment of , the ability to transfer energy. If this assessment is for reliability, it will be conducted using power flow and stability programs. These programs to not assess anything based on

Organization	Yes or No	Question 2 Comment
		energy. Wouild it be more appropriate to use "power" instead of "energy" in the purpose statement?
Response: To further align the purpose statement with the content of the standard, it has been revised to "To ensure that Planning Coordinators have a methodology for, and perform an annual assessment to identify potential future Transmission System weaknesses and limiting facilities that could impact the Bulk Electric System's (BES) ability to reliably transfer energy in the Near-Term Transmission Planning Horizon." The SDT see does not believe changing energy to power would add any additional clarity to the standard.		
United Illuminating Co.	No	UI disagrees. The purpose is to establish a methodology and apply the methodology to determine the transfer capability. The Standard is not addressing the identification of weaknesses or impact to BES reliability. The assessment of the impact of the transfer capabilities determined by FAC-013 is made in the Transmission Planning Process (TPL standards). The proper purpose statement is: "To ensure that Planning Coordinators have a methodology for, and perform an annual assessment of the ability to transfer energy (in the Near-Term Transmission Planning Horizon)."
Response: The purpose of the standard is to focus more on the limiting facilities that are identified under the stress of specific energy transfers, rather than the specific values. Changes in energy transfers can occur for a variety of reasons (change in resource plans, changes in energy costs, new generation sources,..) and understanding the potential impact on facilities, (and thus reliability), is important to effective transmission planning. The SDT does not disagree that it may be appropriate to move the requirements of FAC-013-2 into the TPL standards at some time in the future. FERC Order 729 addressed the need for the standard and determined in paragraph 290 that the assessment of transfer capability "will be useful for long-term planning, in general, by measuring sufficient long-term capacity needed to ensure the reliable operation of the Bulk-Power System." The standard drafting team is charged with addressing FERC's directives to the ERO and has sought to find an equally effective and efficient means to meet FERC's directive - while maximizing the benefit to reliable transmission system planning.		
Ameren	No	As we all know, transfer capability is not a single value and is dependent on the selection and participation of sources and sinks on the defined transmission system. A multitude of assumptions goes into the development of the power system model, and the transfer capability study/assessment assumptions need to be discussed and documented.
Response: The SDT agrees and R1 is intended to ensure that documentation of assumptions and criteria is provided in the transfer capability methodology.		
Tucson Electric Power	No	The meaning of Energy Transfers is not clear. Need a clear definition of what is meant by "ability to transfer energy". We currently conduct Planning Horizon (Year 2 through 10) LSC reliability studies to serve Native and Network Customer loads, while meeting TPL standards. I do not believe it is reasonable to ask individual BAs to determine transmission network transfer capability since it would inevitably involve multiple-BAs systems. Perhaps this is a role for the WECC Regional Transmission Expansion Plan developers.

Organization	Yes or No	Question 2 Comment
Response: The focus of the standard is on identifying limiting facilities under the stress of increased transfers. FAC-013-2 has been written to provide flexibility to the Planning Coordinator to perform the assessment of impact of transfers on reliability according to their knowledge of the behavior and needs of their system. The applicability was assigned to the PC because of their generally wider area view and to be in accord with a FERC directive.		
Florida Municipal Power Agency	Yes	
SERC Planning Standards Subcommittee	Yes	
PacifiCorp	Yes	
Georgia Transmission Corporation	Yes	
Manitoba Hydro	Yes	
Orlando Utilities Commission	Yes	
American Electric Power	Yes	
Duke Energy	Yes	
Tri-State Generation & Transmission Assn., Inc.	Yes	
South Carolina Electric and Gas	Yes	
Xcel Energy	Yes	
Independent Electricity System Operator	Yes	
Tri-State Generation and	Yes	

Organization	Yes or No	Question 2 Comment
Transmission Assn., Inc.		
Tennessee Valley Authority	Yes	

3. The SDT has added a Requirement R6. The Requirement R6 reads "If a recipient of a documented Transfer Capability assessment requests data to support the assessment, the Planning Coordinator shall provide such data to that entity within 45 calendar days of receipt of the request." Do you agree that the Requirement is necessary for verification of the assessment?

Summary Consideration: Because of concerns regarding restrictions on dissemination of CEII and commercially sensitive information, R6 has been reworded as, "If a recipient of a documented Transfer Capability assessment requests data to support the assessment results, the Planning Coordinator shall provide such data to that entity within 45 calendar days of receipt of the request. The provision of such data shall be subject to the legal and regulatory obligations of the Planning Coordinator's area regarding the disclosure of confidential and/or sensitive information."

The SDT believes the 45 calendar day deadline is appropriate for providing data that the Planning Coordinator used in the assessment and would reasonably be expected to be readily available.

The standard does not address the format in which data must be provided, but it is reasonable to assume that it would be in the form the Planning Coordinator used for the studies. It would not be reasonable to place the burden on the Planning Coordinator for providing the data in all the formats that requestors may desire

Organization	Yes or No	Question 3 Comment
Northeast Power Coordinating Council	No	This requirement states that the Planning Coordinator provide the data to support the assessment results upon request. Such entities may be restricted from receiving such data as it may be CEII, market sensitive data, or violate other Planning Coordinator policies.
ISO New England, Inc.	No	
Consolidated Edison Co. of NY, Inc.	No	
Response: Because of concerns regarding restrictions on dissemination of CEII and commercially sensitive information, R6 has been reworded as "If a recipient of a documented Transfer Capability assessment requests data to support the assessment results, the Planning Coordinator shall provide such data to that entity within 45 calendar days of receipt of the request. The provision of such data shall be subject to the legal and regulatory obligations of the Planning Coordinator's area regarding the disclosure of confidential and/or sensitive information**."**		
Florida Municipal Power Agency	No	Please see response to Question 5

Organization	Yes or No	Question 3 Comment
Response: Please see response to question 5.		
SERC Planning Standards Subcommittee	No	It should be made clear that providing CEII data would not be included in this requirement.
Response: Because of concerns regarding restrictions on dissemination of CEII and commercially sensitive information, R6 has been reworded as "If a recipient of a documented Transfer Capability assessment requests data to support the assessment results, the Planning Coordinator shall provide such data to that entity within 45 calendar days of receipt of the request. The provision of such data shall be subject to the legal and regulatory obligations of the Planning Coordinator's area regarding the disclosure of confidential and/or sensitive information."		
MRO's NERC Standards Review Subcommittee	No	Requirement R6 does not serve a transmission system reliability purpose and should be removed. The FAC-013-2 standard should be converted to an appropriate open access, economic (e.g. NAESB) standard.
American Transmission Company	No	Requirement R6 does not serve a transmission system reliability purpose and should be removed, unless the FAC-013-2 standard is converted an appropriate open access, economic (e.g. NAESB) standard
Response: R6 serves a reliability purpose; it provides sufficient data for those entities with a reliability related need to verify data and assumptions, and to validate assessments.		
IRC Standards Review Committee	No	R6 is an unnecessary administrative requirement that provides no reliability benefit. It attempts to implement the open access concepts of transparency and comparability by allowing a third party to repeat or mimic the Planning Coordinator's calculations. It is strictly a commercial issue and simply does not belong in enforceable reliability standards. Further, it presumes that the Planning Coordinator is not able to perform its function and that compliance monitoring and enforcement processes of NERC and the Regional Entities will not detect deficiencies which will result in mitigation plans to correct deficiencies. Furthermore, some entities simply cannot have the data without violating FERC standards of conduct and data confidentiality policies.
ERCOT	No	
Response: The SDT does not believe that R6 is an unnecessary administrative requirement and it does provide reliability benefits. R6 serves a reliability purpose; it provides sufficient data for those entities with a reliability related need to verify data and assumptions, and to validate assessments. R6 does not presume that the Planning Coordinator may not be capable of performing the function nor does it presume NERC and Regional Entities' Compliance Monitoring and Enforcement Processes will not be able to identify deficiencies and will not be able to direct mitigation plans to correct those deficiencies. It does presume that NERC registered functional entities will be provided greater transparency of the data, assumptions and assessments. Because of concerns regarding restrictions on dissemination of CEII and commercially sensitive information, R6 has been reworded as "If a recipient of a documented Transfer Capability assessment requests data to support the assessment results, the Planning Coordinator shall provide such data to that entity within 45 calendar		

Organization	Yes or No	Question 3 Comment
days of receipt of the request. The provision of such data shall be subject to the legal and regulatory obligations of the Planning Coordinator's area regarding the disclosure of confidential and/or sensitive information."		
Independent Electricity System Operator	No	While the IESO generally supports the underlying rationale for Requirement R6, it must be further revised to respect the reality of there being differing (and potentially conflicting) data confidentiality provisions and regulatory environments across North America. The IESO recommends that an additional statement be added to Requirement R6, to the following effect: "Upon receiving a request by a recipient of a documented Transfer Capability assessment for data in support the assessment, a Planning Coordinator shall provide the requestor with such data within 45 calendar days. Notwithstanding the foregoing sentence, the provision of such data shall be subject to the legal and regulatory obligations of the Planning Coordinator's area regarding the disclosure of confidential and/or sensitive information."
Response: Because of concerns regarding restrictions on dissemination of CEII and commercially sensitive information, R6 has been reworded as "If a recipient of a documented Transfer Capability assessment requests data to support the assessment results, the Planning Coordinator shall provide such data to that entity within 45 calendar days of receipt of the request. The provision of such data shall be subject to the legal and regulatory obligations of the Planning Coordinator's area regarding the disclosure of confidential and/or sensitive information."		
New York Independent System Operator	No	This is an unnecessary administrative requirement that provides no reliability benefit and presumes that the Planning Coordinator is not able to perform its function. Furthermore, this requirement does not recognize that recipients of the Transfer Capability assessment may be restricted from receiving the assessment data as the data may be CEII or confidential.
Response: R6 serves a reliability purpose; it provides sufficient data for those entities with a reliability related need to verify data and assumptions and to validate assessments. Because of concerns regarding restrictions on dissemination of CEII and commercially sensitive information, R6 has been reworded as "If a recipient of a documented Transfer Capability assessment requests data to support the assessment results, the Planning Coordinator shall provide such data to that entity within 45 calendar days of receipt of the request. The provision of such data shall be subject to the legal and regulatory obligations of the Planning Coordinator's area regarding the disclosure of confidential and/or sensitive information."		
Tennessee Valley Authority	No	The intent of this requirement is unclear. To understand who is intended by the phrase "recipient of a documented Transfer Capability assessment", one must trace back to R5, and then R2 to understand that it is referring to 1) each adjacent Planning Coordinator, 2) each Transmission Planner within the Planning Coordinator's Planning Coordinator area, and 3) each other functional entity that has a reliability-related need and has made a written request for the applicable Planning Coordinator's assessment of Transfer Capabilities. No bounds are defined for the scope of "data" these entities may request. Some of the data may be considered CEII, and the timeline for release of such information should be taken into consideration if non-disclosure agreements are not already in place with the potential requestors.

Organization	Yes or No	Question 3 Comment
Response: R6 serves a reliability purpose; it provides sufficient data for those entities with a reliability related need to verify data and assumptions and to validate assessments. Because of concerns regarding restrictions on dissemination of CEII and commercially sensitive information, R6 has been reworded as "If a recipient of a documented Transfer Capability assessment requests data to support the assessment results, the Planning Coordinator shall provide such data to that entity within 45 calendar days of receipt of the request. The provision of such data shall be subject to the legal and regulatory obligations of the Planning Coordinator's area regarding the disclosure of confidential and/or sensitive information."		
Tucson Electric Power	No	
PacifiCorp	Yes	Providing the requested data within 45 days is sufficient if the format of the data provided by the Planning Coordinator may be in the software format currently in use by the entity developing such data, although 60 days would be more reasonable. Additional time would be required if a general use format is necessary. Also, all rights to the data would remain with the originating registered entity and further disclosure by any recipients would be in violation of existing non-disclosure agreements.
Response: The SDT believes the 45 calendar day deadline is appropriate for providing data that the Planning Coordinator used in the assessment and would reasonably be expected to be readily available. The standard does not address the format in which data must be provided, but it is reasonable to assume that it would be in the form the Planning Coordinator used for the studies. It would not be reasonable to place the burden on the Planning Coordinator for providing the data in all the formats that requestors may desire. Because of concerns regarding restrictions on dissemination of CEII and commercially sensitive information, R6 has been reworded as "If a recipient of a documented Transfer Capability assessment requests data to support the assessment results, the Planning Coordinator shall provide such data to that entity within 45 calendar days of receipt of the request. The provision of such data shall be subject to the legal and regulatory obligations of the Planning Coordinator's area regarding the disclosure of confidential and/or sensitive information."		
Bonneville Power Administration	Yes	The requirement is necessary for the verification of the assessment. However, is the 45 calendar days dead-line necessary? FAC-014-2, Requirement R5 has similar language, but does not have a dead-line specified for responding. Also, the TPL-001 thru TPL-004 do not have specified time-lines for responding.
Response: The SDT believes the 45 calendar day deadline is appropriate for providing data that the Planning Coordinator used in the assessment and would reasonably be expected to be readily available. It is also necessary for establishing appropriate compliance criteria.		

Organization	Yes or No	Question 3 Comment
Orlando Utilities Commission	Yes	Is the intent of R6 limited to a recipient requesting the same data used to make the assessment such that given the same software they could repeat the analysis? If so I would suggest wording as "..requests the data used to make the assessment, the Planning Coordinator shall provide such data to that entity in the formats used or another format agreeable to both parties." As written it could result in wider requests for data and/or requests for data in a format other then that used for the study.
Response: The standard does not address the format in which data must be provided, but it is reasonable to assume that it would be in the form the Planning Coordinator used for the studies. It would not be reasonable to place the burden on the Planning Coordinator for providing the data in all the formats that requestors may desire.		
South Carolina Electric and Gas	Yes	It should be made clear that providing CEII data would not be included in this requirement.
Response: Because of concerns regarding restrictions on dissemination of CEII and commercially sensitive information, R6 has been reworded as "If a recipient of a documented Transfer Capability assessment requests data to support the assessment results, the Planning Coordinator shall provide such data to that entity within 45 calendar days of receipt of the request. The provision of such data shall be subject to the legal and regulatory obligations of the Planning Coordinator's area regarding the disclosure of confidential and/or sensitive information		
Arizona Public Service Company	Yes	
Georgia Transmission Corporation	Yes	
Manitoba Hydro	Yes	
United Illuminating Co.	Yes	
American Electric Power	Yes	
Duke Energy	Yes	
Tri-State Generation & Transmission Assn., Inc.	Yes	

Organization	Yes or No	Question 3 Comment
Xcel Energy	Yes	
Tri-State Generation and Transmission Assn., Inc.	Yes	

4. The SDT has modified the VSLs to better align with the Requirements. Do you agree that the revised VSLs are now appropriately aligned with the Requirements?

Summary Consideration: Comments were received indicating the VSL's for R1 are incorrect. The SDT believes the existing VSLs are correct and logical and follow NERC's guidance on VSL's for requirements with parts that contribute unequally to the requirement: If a requirement has several parts, and the parts contribute unequally to the reliability-related objective of the requirement, then noncompliance with each of the parts should be clearly associated with at least one of the VSLs. Missing one or two parts of R1.4 is not as significant as missing all of 1.1, 1.2, 1.3. or 1.5. The VSL's for R1 have also been edited to read more clearly. The VSL's for R2 were incorrect and have been revised.

Organization	Yes or No	Question 4 Comment
MRO's NERC Standards Review Subcommittee	No	Missing one of the parts 1.1, 1.2, 1.3 or 1.5 is a Moderate VSL while missing only part of 1.4 is a Lower VSL. This implies that missing one of the parts 1.1, 1.2, 1.3 or 1.5 is deemed to have missed a greater part of the requirement as a whole rather than missing part of 1.4. We disagree and, thus, recommend that the VSLs for missing one of 1.1, 1.2, 1.3 or 1.5 should start at a Lower VSL and increment to the next VSL for each successive missing part.
ERCOT	No	
Response: The SDT believes the existing VSLs are correct and logical and follow NERC's guidance on VSL's for requirements with parts that contribute unequally to the requirement: If a requirement has several parts, and the parts contribute unequally to the reliability-related objective of the requirement, then noncompliance with each of the parts should be clearly associated with at least one of the VSLs. Missing one or two parts of R1.4 is not as significant as missing all of 1.1, 1.2, 1.3. or 1.5.		
IRC Standards Review Committee	No	Missing one of the parts 1.1, 1.2, 1.3 or 1.5 is a Moderate VSL while missing only part of 1.4 is a Lower VSL. This implies that missing one of the parts 1.1, 1.2, 1.3 or 1.5 are deemed to have missed a greater part of the requirement as a whole than missing part of 1.4. We disagree and, thus, recommend that the VSLs for missing one of 1.1, 1.2, 1.3 or 1.5 should start at a Lower VSL and increment to the next VSL for each successive missing part.AESO does not comment on VSLs as they are established by regulatory authorities in Alberta.
Response: The SDT believes the existing VSLs are correct and logical and follow NERC's guidance on VSL's for requirements with parts that contribute unequally to the requirement: If a requirement has several parts, and the parts contribute unequally to the reliability-related objective of the requirement, then noncompliance with each of the parts should be clearly associated with at least one of the VSLs. Missing one or two parts of R1.4 is not as significant as missing all of 1.1, 1.2, 1.3. or 1.5.		
Duke Energy	No	The VSLs for R2 are incorrect. The paragraph after the "OR" in the Lower VSL is not a violation. To correct

Organization	Yes or No	Question 4 Comment
		this, replace the paragraph after the “OR” in the Lower VSL with the corresponding paragraph from Moderate. Likewise, move the paragraph after the “OR” in Higher to Moderate. Also, modify the paragraph after the “OR” in High to make it 90 to 120 days. Then add a new paragraph after the “OR” in Severe, making it more than 120 days after receipt of a request.
Response: The SDT agrees and has made the suggested changes.		
Tri-State Generation & Transmission Assn., Inc.	No	Tri-State believes that the intent of the R1. VSL is that a failure to incorporate the number specified in the level of the requirements R1.1, R1.2, R1.3, or R1.5 requires that the word “and” be changed to “or” in the Moderate, High, and Severe VSLs.The Moderate, High, and Severe levels use the term “Planning Transfer Methodology” instead of “Transfer Capability Methodology” in the last section of each of those VSLs for R1.The “OR” clause in each of the Severe VSLs of R3., R4., R5., and R6. is unnecessary and should be removed. The only time the clause would be in effect is if an audit occurred while the non-compliance period was ongoing and the VSLs as proposed would require a Severe level for as little as a single day’s non-compliance.
Response: The SDT modified the standard to read “The Planning Coordinator has a planning transfer capability methodology, but failed to incorporate one of the following Parts of Requirement R1 into that methodology: • Part 1.1 • Part 1.2 • Part 1.3 • Part 1.5 With respect to the second part of your concern - the Severe VSL was intended to address the situation where the PC has no evidence of having tried to meet the requirement.		
Independent Electricity System Operator	No	We do not have any concerns with the revised VSLs but caution that they may need to be revised depending on the SDT’s response to our comments under Q3 and Q5, and any other industry comments.
Response: The VSL’s have been corrected to use the correct term for Transfer Capability methodology.		
Bonneville Power Administration	Yes	The new VSLs are appropriately aligned with the Requirements.
Western Electricity Coordinating Council	Yes	Thank you for addressing the issue with the Low and Moderate VSL for R1.

Organization	Yes or No	Question 4 Comment
Response: Thank you		
Northeast Power Coordinating Council	Yes	
Florida Municipal Power Agency	Yes	
PacifiCorp	Yes	
Arizona Public Service Company	Yes	
Georgia Transmission Corporation	Yes	
Manitoba Hydro	Yes	
United Illuminating Co.	Yes	
Orlando Utilities Commission	Yes	
American Electric Power	Yes	
Consolidated Edison Co. of NY, Inc.	Yes	
South Carolina Electric and Gas	Yes	
American Transmission Company	Yes	
Tucson Electric Power	Yes	

5. Please provide any other comments (that you have not already provided in response to the questions above) that you have on the proposed standard.

Summary Consideration: Based on industry feedback, the SDT has made several wording changes to add clarity to requirements.

For Requirement R1, Part 1.4.1 ad 1.4.2, the term, "long-term" was added to qualify the types of outages that must be considered.

For clarity, Requirement R2, Part 2.2 was rephrased to clearly address distribution of the methodology, and to Requirement R5, to require providing entities with a reliability-related need for the assessment results with those results.

Commenters identified that the term "Transfer Capability Methodology" is capitalized, implying that this is a defined term but this term is neither defined in the NERC Glossary nor being proposed in the standard as a new term. The SDT has modified the draft standard to use the lower-case lettering for the term "Transfer Capability methodology".

Organization	Yes or No	Question 5 Comment
Northeast Power Coordinating Council	Yes	R1.1 - This requirement is unclear as written. Using the term "transfers" suggests that the values are known at the initiation of the study. "Transfers" be replaced with "interfaces" to become "Criteria for the selection of the interfaces to be assessed."R1.2 - The intent of this requirement is unclear. If the point of this effort is to determine transfer limits in a planning space, why would the analysis "respect" known SOLs. More confusion is added if the system being analyzed contains transmission upgrades which are not reflected in current known SOLs. This should be deleted, or consider revision to read: "A statement that the assessment shall consider for evaluation known system operating limits (SOLs)". The term "respect" implies that known SOLs will be adhered to without the benefit of needed periodic re-evaluation. In the planning, as well as real-time operation, SOLs are dynamic, and may change as a result of system topography/operational changes. R1.3 - Revise to read "A statement that the assumptions and criteria used to perform the assessment are consistent with the Planning Coordinator's planning criteria." Planning practices should always reflect current planning criteria. R1.4.1 - Revise to read "Generation dispatch, including but not limited to long term planned outages, additions and retirements." R1.4.2 - Revise to read "Transmission System topology, including but not limited to long term planned outages; transmission additions, upgrades and retirements." R1.4.3 - Revise to read "System demand, including peak demand". Transfer limits at peak load are used in many Reliability Coordinator reliability assessments.
Consolidated Edison Co. of NY, Inc.	Yes	

Organization	Yes or No	Question 5 Comment
		R1.4.4 - Revise to read "Current approved Firm Transmission uses". Only approved firm transmission service should be embedded in the base case (i.e. not subject to periodic assessments) because it is reasonable to expect that these types of transfers have received formal approval after a comprehensive evaluation. Any other type of transfers may not be thought of being inconsequential to reliability until an evaluation is performed. It is also unclear what the meaning of "uses" is in this context. R1.4.5 - What it is meant by "parallel path loop flow adjustment"? Provide an illustrative example, and it should be added as a definition and to the NERC Glossary. R1.5 - This requirement should be revised to specify that simulations of transfers are performed mainly through the adjustment of generation only, not load. Changing the dispatch of generation resources is, in the vast majority of cases, the way that transfers are effected in real-time, and simulations should reflect this fact. The use of Phase Angle Regulators must also be considered, and the Requirement worded to reflect the use of that equipment. R3 - There should be a time limit with respect to when the recipient of a Transfer Capability Methodology can provide documented concerns. R5 - It is unclear whether or not R5 includes those recipients under R2.2. R5 should be modified to state that recipients as a result of R2.2 must specifically request the assessment, and then allow 30 days from the time of request for it to be provided. Otherwise, R5 may become impossible to meet. As an example, if an entity requests the Transfer Capability Methodology under R2.2.2 six months after the assessment was completed, it is not possible to provide the assessment 45 days after it was completed.

Response: The SDT thanks you for providing your comments. We have modified R 1.4.1, R 1.4.2 and R5 based on your comments. However, we have not changed other requirements.

R 1.1 –The SDT believes the term "transfer" correctly describes the driver that is being used to stress the system.

R1.2 - The SDT believes the word "'respect" correctly describes the treatment of known SOLs and is the term used in the existing FAC-012.

R1.3 - The SDT believes the term "Planning practices" is a broader term than "planning criteria" and should be used. We have changed "assessments" to "assessment".

R1.4.3-The STD does not want to specify that transfers be imposed on the system during peak demand. As written the requirement is to document the demand level when the assessment was conducted. If the .planner wants to include transfers at the system peak they need to provide that information in the documentation.

R1.4.4-The STD does not want to restrict the modeled Transmission uses to only "approved Firm" uses. The requirement is to document the Transmission uses

Organization	Yes or No	Question 5 Comment
modeled in the assessment. If the planner wants to restrict the uses to approved firm they need to provide that information in the documentation. R1.4.5-The STD does not believe developing a definition of parallel path loop flow adjustment would be productive. Parallel path and loop flow are commonly used terms in the industry, for example MOD 001-1a, R9. The requirement provides the planner with the flexibility to address parallel path (loop) flow in their assessment and requires them to provide documentation about how they are addressed. R1.5- The STD does not want to restrict how the transfers are simulated. If the planner wants to simulate transfers only through generation shifts they need to provide that information in the assessment. R 3-The SDT believes that there does not need to be a time limit imposed on when the requestor provide written documentation regarding their concerns. Conditions may change after a methodology is implemented such that new concerns may be identified by entity. R5 has been edited to read, "Each Planning Coordinator shall make the documented Transfer Capability assessment results available within 45 calendar days of the completion of the assessment to the recipients of its transfer capability methodology pursuant to R2.1 and R2.2. However, if a functional entity that has a reliability related need for the results of the annual assessment of the Transfer Capabilities makes a written request for such an assessment after the completion of the assessment, the Planning Coordinator shall make the documented Transfer Capability assessment results available to that entity within 45 calendar days of receipt of the request."		
ISO New England, Inc. New York Independent System Operator		R1.1 - This requirement is unclear as written. Using the term "transfers" suggests that the values are known at the initiation of the study. We suggest "transfers" be replaced with "interfaces" to become "Criteria for the selection of the interfaces to be assessed." R1.2 - The intent of this requirement is unclear. If the point of this effort is to determine transfer limits in a planning space, why would the analysis respect known SOLs. More confusion is added if the system being analyzed contains transmission upgrades which are not reflected in current known SOLs. This should be deleted. R1.4.4 - It is unclear what the meaning of "uses" is in this context. R3 - There should be a time limit with respect to when the recipient of a Transfer Capability Methodology can provide documented concerns. R5 - It is unclear whether or not R5 includes those recipients under R2.2. R5 should be modified to state that recipients as a result of R2.2 must specifically request the assessment and then allow 30 days from the time of request for it to be provided. Otherwise, R5 may become impossible to meet. As an example, if an entity requests the Transfer Capability Methodology under R2.2.2 6 months after the assessment was completed, it is not possible to provide the assessment 45 days after it was completed.

Organization	Yes or No	Question 5 Comment
Response: The SDT thanks you for providing your comments. We have modified R5 based on your comments. However, we have not changed other requirements. R 1.1 –The SDT believes the term "transfer" correctly describes the driver that is being used to stress the system. R1.2 - The SDT believes the word "'respect" correctly describes the treatment of known SOLs and is the term used in the existing FAC 012. R1.4.4-The STD believes that the word "uses" is a commonly understood term that includes network and point to point Transmission uses. The requirement is to document the Transmission uses modeled in the assessment. R 3-The SDT believes that there does not need to be a time limit imposed on when the requestor provides written documentation regarding their concerns. Conditions may change after a methodology is implemented such that new concerns may be identified by entity. R5 has been edited to read, "Each Planning Coordinator shall make the documented Transfer Capability assessment results available within 45 calendar days of the completion of the assessment to the recipients of its transfer capability methodology pursuant to R2.1 and R2.2. However, if a functional entity that has a reliability related need for the results of the annual assessment of the Transfer Capabilities makes a written request for such an assessment after the completion of the assessment, the Planning Coordinator shall make the documented Transfer Capability assessment results available to that entity within 45 calendar days of receipt of the request."		
Florida Municipal Power Agency	Yes	R2 is confusing. The main requirement requires distribution of the methodology; however, bullet 2.2 requires distribution of the results. Which is it? It would seem bullet 2.2 needs to be redrafted to refer to the methodology since the distribution of results is in R5. R5 needs more clarity. It says that the PC must make the results available, but to whom? Due to CEII, we presume this is not for publishing on a web-site, so, we presume that the recipients would be the same as in R2, but, R5 should specifically say so. Would it make sense to move R4 to before R2 and combine R2 with R5 , and R3 with R6 and have R2/R5 and R3/R6 refer to both the methodology and results?
Response: R2 - Thank you for your comments. R2.2 requires the distribution of the Planning Coordinator's transfer capability methodology, not the assessment results. The SDT clarified this in the revised standard. R5 has been edited to read, "Each Planning Coordinator shall make the documented Transfer Capability assessment results available within 45 calendar days of the completion of the assessment to the recipients of its transfer capability methodology pursuant to R2.1 and R2.2. However, if a functional entity that has a reliability related need for the results of the annual assessment of the Transfer Capabilities makes a written request for such an assessment after the completion of the assessment, the Planning Coordinator shall make the documented Transfer Capability assessment results available to that entity within 45 calendar days of receipt of the request."		

Organization	Yes or No	Question 5 Comment
Move R4 to before R2 and combine R2 with R5 was suggested. The SDT believes the current ordering provides the best clarity. R1, R2 and R3 deal with the methodology and R4, R5 and R6 deal with the assessment.		
SERC Planning Standards Subcommittee	Yes	The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Planning Standards Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.
Response: Noted.		
MRO's NERC Standards Review Subcommittee		Requirement R1.2 should explicitly state that the assessment shall respect known Planning Horizon SOLs because the standard is applicable for the planning horizon and not the operating horizon. Otherwise, the lack of qualification could lead to interpretation issues with this Requirement.
Response: For R1.2, the SOLs could be either the planning horizon or the operating horizon. R1.2 requires a "statement that the assessment shall respect known System Operating Limits (SOLs)." Although the standard applies to the planning horizon, good planning practice may require operating horizon SOLs if the SOLs are known and the SOLs could impact the planning horizon; therefore the SDT does not believe that it should only be planning SOLs.		
IRC Standards Review Committee	Yes	For bullet 1.2, do only the SOLs in the planning horizon governed by FAC-011-2 apply or do those in the operating horizon also apply? Since the standard applies to the planning horizon, it should only be planning SOLs. Furthermore, this bullet is administrative in nature and should be modified. A statement that SOLs shall be respected provides no reliability value. How does an entity prove compliance with R3? How does it prove it did not receive comments from a recipient of the methodology? R3 should be removed from the standard as it is an administrative requirement that is unnecessary, contrary to the results-based standards. What value does it provide other than to make third parties feel like they can force a response to their input? Transfer capability calculations have been performed for so long and are so well understood by industry, it is hard to fathom a third party providing any valuable technical input that a Planning Coordinator has not already considered. This requirement presumes that the Planning Coordinator may not be capable of performing the function for which they are registered and certified. It further presumes that NERC and Regional Entities' Compliance Monitoring and Enforcement Processes will not be able to identify deficiencies with complying with Requirement R1. Furthermore, the requirement to respond to all technical comments and/or revise the methodology would be a significant administrative burden to the Planning Coordinators. Part 2.2 should be either be removed due to its subjective nature or criteria for requesting such data should be added to clarify what entities can request such data, under what circumstances they can do so, and how disputes regarding such requests are to be resolved. More specifically, R3 contains no indication regarding the entity that makes the determination that a
ERCOT	No	

Organization	Yes or No	Question 5 Comment
		functional entity had a reliability-related need to the results of the annual assessment of Transfer Capabilities. In R1, the term Transfer Capability Methodology is used and capitalized. It does not have a current definition in the NERC glossary and the SDT did not propose a definition. It should be defined or made lower case.
Response: For R1.2, the SOLs could be either the planning horizon or the operating horizon. R1.2 requires a "statement that the assessment shall respect known System Operating Limits (SOLs)." Although the standard applies to the planning horizon, good planning practice may require operating horizon SOLs if the SOLs are known and the SOLs could impact the planning horizon; therefore the SDT does not believe that it should only be planning SOLs. Whether R1.2 is "is administrative in nature" or not, it ensures that Planning Coordinators must include known SOLs or suffer a penalty for not including them. The SDT believes that including known SOLs does have reliability value. "How does an entity prove compliance with R3?" As stated in M3, "Each Planning Coordinator shall have evidence, such as dated e-mail or dated transmittal letters, that the Planning Coordinator provided a written response to that commenter in accordance with Requirement R3." "How does it prove it did not receive comments from a recipient of the methodology?" In the standard's Data Retention section, "The Planning Coordinator shall retain evidence to show compliance with Requirements R3, R4, R5 and R6 for the most recent assessment." The evidence could include any comments received and could include an attestation if no comments were received. The SDT does not believe that "R3 should be removed from the standard as it is an administrative requirement that is unnecessary, contrary to the results-based standards." Requiring the Planning Coordinator to respond to commenters is necessary as it may lead to changes in the methodology; at the very least, it makes the methodology more transparent to all NERC registered functional entities. The SDT does not agree that Planning Transfer Capability methods are well understood or transparent to all NERC registered functional entities that may comment. R3 does not presume "that the Planning Coordinator may not be capable of performing the function for which they are registered and certified" nor does it presume "that NERC and Regional Entities' Compliance Monitoring and Enforcement Processes will not be able to identify deficiencies." It does presume that NERC registered functional entities may need greater transparency on the methodology. It is unclear if R3 "would be a significant administrative burden to the Planning Coordinators." If R3 does become a significant administrative burden to some Planning Coordinators, then it would indicate that their methodology is not transparent to other reliability related entities. It is unclear why the commenter believes that R2.2 is subjective. In R2.2, the entity making a request for a Transfer Capability assessment must be a NERC registered functional entity. The requirement is in the context of a NERC Reliability Standard. It is evident that NERC registered functional entities are being addressed. Note that the SDT did modify R2, Part 2.2 to clarify that the intent is to provide the methodology to any functional entity that has a reliability-related need for the methodology. The SDT has modified the draft standard to use the lower-case lettering for the word, "methodology" throughout the standard.		
Arizona Public Service Company		FAC-013-2 appears to duplicate assessment study work required in MOD-001. The MOD-001, MOD-028, MOD-029, and MOD-030 standards essentially require that entities have a methodology and perform an Available Transfer Capability Assessment, with potential of also having to perform a Total Transfer Capability assessment, with no defined date-range which, for some utilities, will be up to 10 years. FAC-013-2 requires entities perform a Transfer Capability assessment for years 1-5, thereby making FAC-013-2 a duplicative

Organization	Yes or No	Question 5 Comment
		process.
Response: The SDT recognizes that FAC-013-2 may use the same study work that is used in MOD-029-1; that would not be true for entities that use MOD-028-1 and MOD-030-2. Regardless, the methodologies in the MOD standards DO have a defined date range (the Operations Planning horizon). FAC-013-2 has a different date range (the Near-Term Planning Horizon). Therefore the standards are not duplicative for WECC and definitively not duplicative for non-WECC entities; even if some of the study work is the same study work that is used in MOD-029-1. FAC-013-2 has been written to provide flexibility to the Planning Coordinator to perform the assessment according to their knowledge of the behavior and needs of their system. The MOD Standards do not afford such flexibility.		
Western Electricity Coordinating Council		We agree that the requirements of proposed FAC-013-2 pose no threat to reliability and, in fact, are beneficial to reliability. However, we also believe that the requirements of proposed FAC-013-2 are duplicative of the efforts required by FAC-010, FAC-014, and the TPL Planning Standards TPL-001 through TPL-004. For clarity and ease of implementation, the requirements of proposed FAC-013-2 should be incorporated as new requirements or added into the appropriate requirements of existing standards FAC-010, FAC-014, and the TPL Planning Standards. The efforts to implement FERC's directives into the TPL-001 through TPL-004 planning standards have resulted in clarification of multiple sensitivities that must be considered when conducting the Transmission Assessments required by the new TPL-001-1 planning standard. The information gleaned by conducting and assessing these sensitivity studies would provide the Planning Coordinator with the same information regarding the impact of system changes on their Transfer Capability as obtained by meeting the requirements in the proposed FAC-013-2. Because some entities my vote in the negative for FAC-013-2 out of concerns related to double jeopardy for any potential violations of the proposed FAC-013-2 and currently existing standards, incorporating the requirements of FAC-013-2 into the appropriate existing standards may be more acceptable to the industry.
Response: The SDT recognizes that FAC-013-2 may use some of WECC's required efforts in FAC-010, FAC-014, and the TPL Planning Standards TPL-001 through TPL-004; that would not necessarily be true for entities outside of WECC. Regardless, the methodology in FAC-013-2 has a different date range (the Near-Term Planning Horizon). Therefore the standards are not completely duplicative for WECC and definitively not duplicative for non-WECC entities; even if some of the effort is the same work that is used in other standards. FAC-013-2 has been written to provide flexibility to the Planning Coordinator to perform the assessment according to their knowledge of the behavior and needs of their system. The MOD and TPL Standards do not afford such flexibility.		
Ameren	Yes	R1.4.3 should be modified to be System demand, including but not limited to forecast peak demand and appropriate load distribution. R1.4.6 should be limited to single contingency events for the transfer capability values to have meaning. System performance deficiencies for multiple contingency events can be mitigated by dropping of system load under the existing TPL standards.

Organization	Yes or No	Question 5 Comment
		R1.4.8 should be added to cover distribution factor cutoff assumptions. In addition, the new MOD-004 standard has a requirement R6 to establish a CBM value for each ATC Path to be used in planning years 2 through 10. This applies to the Transmission Planner, but should be identified in the assumptions.
Response: FAC-013-2 has been written to provide flexibility to the Planning Coordinator to perform the assessment according to their knowledge of the behavior and needs of their system. The SDT does not believe it is appropriate to specify load level, contingency events, nor cut off factors to be used in the assessment.		
Duke Energy	Yes	Duke Energy appreciates the work of the drafting team and offers the following clarifying changes for further improvement to the standard: o As written, R2.2 is hard to follow. Suggest rewriting as follows: "Distribute the results of the annual assessment of Transfer Capabilities to any other functional entity that has a reliability-related need, within 30 days of receiving a written request." o As written, R4 could possibly allow the Planning Coordinator to conduct an assessment based on a simulation that has not been updated. We believe the intent was to require a simulation to be performed each calendar year and assessment conducted based on that simulation. To clarify this intent, suggest rewriting as follows: "During each calendar year, each Planning Coordinator shall conduct simulations and document an assessment based on those simulations in accordance with its Transfer Capability Methodology for at least one year in the Near-Term Transmission Planning Horizon."
Response: R2.2 The SDT agrees with the proposed language in R2.2 and has incorporated the intent of this suggestion in the revised standard. The revised standard requires distribution of the methodology under R2, Part 2.2 and distribution of the assessment results under R5 – in both cases to those entities with a reliability related need for the information. R4. The SDT agrees with the proposed language in R4 and will incorporate it into the standard.		
Tri-State Generation & Transmission Assn., Inc.	Yes	Add the following to the end of the sentence in R5: "...and any other functional entity in whose system the assessment finds a future weakness or limiting Facility." M5 does not need to change but the VSL for R5 would also need to have similar language inserted.
Response: The SDT agrees that sharing of information between reliability related entities is important and has incorporated requirements to share assessment information with neighboring entities. The SDT does not believe it would be appropriate to have an auditable and sanctionable requirement to share beyond that scope. Because of equivalization in models, less familiarity with the practices and procedures of non-adjacent entities, and the expectation that Planning Coordinators will use good engineering judgment in what information needs to be communicated with others; the SDT does not believe it necessary to add the suggested requirement.		
Xcel Energy	Yes	Xcel Energy is unable to appreciate the BES reliability need for this standard since we believe that a majority,

Organization	Yes or No	Question 5 Comment
		if not all, of its requirements are addressed in existing reliability standards. According to the December 9, 2010 White Paper prepared by the SDT for the draft FAC-013-2, there is a desire to “add to the portfolio of knowledge for planning for future reliable operation of the BES” and “to identify potential future weaknesses in the system.” However, Xcel Energy believes that the proposed FAC-013-2 draft: (1) has Transfer Capability methodology requirements that are effectively the same as, if not duplicative of, those for Planning Horizon SOL Methodology in FAC-010-2, (2) any Transfer Capability Methodology developed per this standard will essentially be no different than one of the three methodologies in MOD-028, MOD-029 or MOD-030, albeit applied to the planning horizon, and (3) the annual transfer capability assessment requirement significantly overlaps with the scope of existing regional planning assessment studies performed per TPL-005 and TPL-006. Therefore, we conclude that the draft FAC-013-2 is not needed to address any reliability gap. We suggest a Transfer Capability assessment belongs in the new TPL-001-2 standard under development, where it could be studied in one of the Near-Term Transmission Planning Horizon studies, and where past Transfer Capability studies (as qualified in R2.6 of TPL-001-2 Draft 6) would be acceptable under the test for no material changes in the BES (don’t force an annual assessment of Transfer Capability).
Response: The comments indicate that the standard is believed to be either duplicative or unnecessary for reliable planning. FERC Order 729 addressed the need for the standard and determined in paragraph 290 that the assessment of transfer capability “will be useful for long-term planning, in general, by measuring sufficient long-term capacity needed to ensure the reliable operation of the Bulk-Power System.” The standard drafting team is charged with addressing FERC’s directives to the ERO and has sought to find an equally effective and efficient means to meet FERC’s directive - while maximizing the benefit to reliable transmission system planning. The SDT does not disagree that it may be appropriate to move the requirements of FAC-013-2 into the TPL standards at some time in the future.		
American Transmission Company	Yes	Requirement R1.2 should explicitly state that the assessment shall respect known Planning Horizon SOLs because the standard is applicable for the planning horizon and not the operating horizon. Otherwise, the lack of qualification could lead to interpretation issues with this Requirement.
Response: For R1.2, the SOLs could be either the planning horizon or the operating horizon. R1.2 requires a “statement that the assessment shall respect known System Operating Limits (SOLs).” Although the standard applies to the planning horizon, good planning practice may require operating horizon SOLs if the SOLs are known and the SOLs could impact the planning horizon; therefore the SDT does not believe that it should only be planning SOLs.		
Tucson Electric Power	Yes	This should be a regional planning activity which includes the Reliability Coordinator, not solely addressed by Planning Coordinators. Need a clear description highlighting the distinctions between Long-Term and Near-Term. How will they be treated differently? E.g. Do what we do today Long-Term and perform more operating type of studies based on MOD-030?

Organization	Yes or No	Question 5 Comment
Response: The SDT agrees that some regions may need to do FAC-013-2 as a regional planning activity that includes the Reliability Coordinator. However, the standard does not prevent FAC-013-2 as a regional planning activity, and the SDT does not believe that FAC-013-2 should be required as a regional planning activity. TPL-001-2 introduces the Long-Term Transmission Planning Horizon definition and provides a clear distinction from the Near-Term Transmission Planning Horizon.		
Independent Electricity System Operator	Yes	We thank the SDT for responding positively to industry comments to remove the two terms PTC and PTCMD, and insert the appropriate wording into the requirements to take care of calculation of Transfer Capability in the Near-Term Transmission Planning Horizon. However, the term "Transfer Capability Methodology" is capitalized, implying that this is a defined term but this term is neither defined in the NERC Glossary nor being proposed in the standard as a new term. We note that this "term" is currently used in both FAC-012-1 and FAC-013-1 though not included in the NERC glossary.We do not have a concern with using this term to indicate that it is a documented methodology for use in performing an annual assessment of Transfer Capability in the Near-Term Transmission Planning Horizon, but it needs to changed to lower case; or else this term needs to be defined.Using lower-case lettering would be consistent with the approach used in the recently approved standard PRC-006-1, where the description "UFLS entities" was established and used within the standard to avoid long-winded requirements that repeatedly refer to the same entities.
Response: Thank you for your comment. The SDT has modified the draft standard to use the lower-case lettering for the term "methodology" throughout the standard.		
Tennessee Valley Authority		TVA appreciates the work of the SDT in developing this revised standard. While we are casting an approval vote, we are doing so with the comment on the new R6 (see response to Q3 above) and the following editorial comments: "transmission" is misspelled (tranmission) in the definition for Near-Term Transmission Planning Horizon. As written, R2.2 is hard to follow. Suggest rewriting as follows: "Distribute the results of the annual assessment of Transfer Capabilities to any other functional entity that has a reliability-related need, within 30 calendar days of receiving a written request." In section D, 1.3 Data Retention - in the first bullet, suggest changing "The Planning Coordinator shall have its in force Transfer Capability Methodology..." to "The Planning Coordinator shall have its current Transfer Capability Methodology..."
Response: The typo has been fixed. ("transmission" is misspelled (tranmission) R2.2 The SDT agrees with the proposed language change and has incorporated this into the revised standard – the revised standard requires the methodology to		

Organization	Yes or No	Question 5 Comment
be provided to entities with a reliability-related need, and R5 has been clarified to indicate that the assessment results must be provided to entities with a reliability-related need for the information, subject to confidentiality rules. D, 1.3 The SDT will adopt the proposed wording change to D, 1.3.		
Orlando Utilities Commission	Yes	Excellent work.
Manitoba Hydro	No	

Consideration of Opinions on Non-binding Poll of VRFs and VSLs — Project 2010-10 – FAC Order 729

Dates of Non-binding Poll: 12/30/2010 - 1/8/2011

Summary Consideration: Most commenters agreed with most of the proposed VRFs and VSLs.

Based on stakeholder comments, the drafting team made conforming changes for improved clarity with the VSLs for R1 and corrected an error in the VSLs for R2. The VSLs for R2 started with a Lower VSL that described acceptable performance (providing within 30 calendar days of a request). The VSLs for R2 were corrected so that the VSL for Lower is 60 days late, with 30-day increments from there.

No changes were proposed or made to any of the VRFs.

If you feel that the drafting team overlooked your comments, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Herb Schrayshuen, at 609-452-8060 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

Balloter	Entity	Segment	Vote	Comment
Venkataramakrishnan Vinnakota	BC Hydro	2	Negative	BC Hydro does not support FAC Order 729 revisions therefore we reject the revisions to the VRF VSL
Pat G. Harrington	BC Hydro and Power Authority	3	Negative	
Clement Ma	BC Hydro and Power Authority	5	Negative	
Gordon Rawlings	BC Transmission Corporation	1	Negative	
Response: The ERO has been directed to make changes to the standard to comply with a FERC directive. Most stakeholders who participated in the comment periods for the revision of FAC-012 and FAC-013 indicated support for this project. FERC Order 729 determined in paragraph 290 that the assessment of transfer capability "will be useful for long-term planning, in general, by measuring sufficient long-term capacity needed to ensure the reliable operation of the Bulk-Power System." The standard drafting team is charged with addressing FERC's directives to the ERO and has sought to find an equally effective and efficient means to meet FERC's directive - while maximizing the benefit to reliable transmission system planning.				
Joseph S. Stonecipher	Beaches Energy Services	1	Negative	(See my comments for the other ballot for Project 2010-10)
Response: Please see the response to your comments in the "Consideration of Comments Report" for comments submitted during the public posting period.				
Gregory Van Pelt	California ISO	2	Negative	Reference the IRC Standards Review Committee Comments
Response: Please see the response to the IRC SRC's comments in the "Consideration of Comments Report" for comments submitted during the public posting				

[1] The appeals process is in the Reliability Standards Development Procedure: http://www.nerc.com/files/RSDP_V6_1_12Mar07.pdf.

Balloter	Entity	Segment	Vote	Comment
period.				
Gregg R Griffin	City of Green Cove Springs	3	Negative	R2 is confusing. The main requirement requires distribution of the methodology; however, bullet 2.2 requires distribution of the results. Which is it? It would seem bullet 2.2 needs to be redrafted to refer to the methodology since the distribution of results is in R5. R5 needs more clarity. It says that the PC must make the results available, but to whom? Due to CEII, we presume this is not for publishing on a web-site, so, we presume that the recipients would be the same as in R2, but, R5 should specifically say so. Would it make sense to move R4 to before R2 and combine R2 with R5 , and R3 with R6 and have R2/R5 and R3/R6 refer to both the methodology and results?

Response: Response:

R2 - Thank you for your comments. R2.2 requires the distribution of the Planning Coordinator's Transfer Capability Methodology, not the assessment results. The revised standard requires distribution of the methodology under R2, Part 2.2 and distribution of the assessment results under R5 – in both cases to those entities with a reliability related need for the information.

R5. Each Planning Coordinator shall make the documented Transfer Capability assessment results available within 45 calendar days of the completion of the assessment to the recipients of its Transfer Capability Methodology pursuant to R2.1 and R2.2. However, if a functional entity that has a reliability related need for the results of the annual assessment of the Transfer Capabilities makes a written request for such an assessment after the completion of the assessment, the Planning Coordinator shall make the documented Transfer Capability assessment results available to that entity within 45 calendar days within receipt of the request

Move R4 to before R2 and combine R2 with R5: The SDT believes the current ordering provides the best clarity. R1, R2 and R3 deal with the methodology and R4, R5 and R6 deal with the assessment.

Balloter	Entity	Segment	Vote	Comment
Randall McCamish	City of Vero Beach	1	Negative	Although the Standard Drafting Team (SDT) has made very significant improvements to the standard, there are a few items that ought to be "fixed". R2 is confusing. The main requirement requires distribution of the methodology; however, bullet 2.2 requires distribution of the results. Which is it? It would seem bullet 2.2 needs to be redrafted to refer to the methodology since the distribution of results is in R5. R5 needs more clarity. It says that the PC must make the results available, but to whom? Due to CEII, we presume this is not for publishing on a web-site, so, we presume that the recipients would be the same as in R2, but, R5 should specifically say so. Would it make sense to move R4 to before R2 and combine R2 with R5 , and R3 with R6 and have R2/R5 and R3/R6 refer to both the methodology and results?
Frank Gaffney	Florida Municipal Power Agency	4	Negative	
David Schumann	Florida Municipal Power Agency	5	Negative	
Richard L. Montgomery	Florida Municipal Power Agency	6	Negative	
Stan T. Rzad	Keys Energy Services	1	Negative	

Response: Response:

R2 - Thank you for your comments. R2.2 requires the distribution of the Planning Coordinator's Transfer Capability Methodology, not the assessment results.

Balloter	Entity	Segment	Vote	Comment
The revised standard requires distribution of the methodology under R2, Part 2.2 and distribution of the assessment results under R5 – in both cases to those entities with a reliability related need for the information. R5. Each Planning Coordinator shall make the documented Transfer Capability assessment results available within 45 calendar days of the completion of the assessment to the recipients of its Transfer Capability Methodology pursuant to R2.1 and R2.2. However, if a functional entity that has a reliability related need for the results of the annual assessment of the Transfer Capabilities makes a written request for such an assessment after the completion of the assessment, the Planning Coordinator shall make the documented Transfer Capability assessment results available to that entity within 45 calendar days within receipt of the request Move R4 to before R2 and combine R2 with R5: The SDT believes the current ordering provides the best clarity. R1, R2 and R3 deal with the methodology and R4, R5 and R6 deal with the assessment.				
Henry Ernst-Jr	Duke Energy Carolina	3	Affirmative	Duke Energy appreciates the work of the drafting team and offers the following clarifying changes for further improvement to the standard. 1. The VSLs for R2 are incorrect. The paragraph after the “OR” in the Lower VSL is not a violation. To correct this, replace the paragraph after the “OR” in the Lower VSL with the corresponding paragraph from Moderate. Likewise, move the paragraph after the “OR” in Higher to Moderate. Also, modify the paragraph after the “OR” in High to make it 90 to 120 days. Then add a new paragraph after the “OR” in Severe, making it more than 120 days after receipt of a request.
Response: Correct – the VSLs for R2 have been revised in support of your comments.				
Ajay Garg	Hydro One Networks, Inc.	1	Abstain	We do not have any concerns with the revised VSLs but caution that they may need to be revised depending on the SDT’s response to our comments on the standard and any other industry comments.
David L Kiguel	Hydro One Networks, Inc.	3	Abstain	
Response: Please see the SDT’s proposed modifications to the standard.				
Kim Warren	Independent Electricity System Operator	2	Negative	If our comments on the requirements are accepted, the VRFs and VSLs will need to be revised.
Response: Please see the SDT’s proposed modifications to the standard.				
Larry E Watt	Lakeland Electric	1	Negative	This standard requires clarification prior to setting of VRF/VSL.
Response: Please see the SDT’s proposed modifications to the standard.				
Mace Hunter	Lakeland Electric	3	Negative	FAC-013-2 lacks clarity, its VSLs are severe for what amounts to a long range sensitivity study, and the requirements should better match the purpose. The whitepaper adds some clarity; however, the clarity should be in the standard, not in associated white papers. It is unclear if the intent is to have the PC determine the amount of internal generation that can be replaced with external generation or if the PC should determine system upgrades using Transfer Capability as a consideration. These two studies would be approached differently and give different results. There are many reasons, beyond the two discussed, to perform

Balloter	Entity	Segment	Vote	Comment
				TC determination. Recommend better refining of the purpose of the Transfer Capability Assessment to be performed. An example of a requirement that requires clarification: Requirement R1, Part R1.3 “A statement that the assumptions and criteria used to perform the assessment are consistent with the Planning Coordinator’s planning practices.”, is intended to provide consistency in the performance of the assessment of transfer capability and the planning practices used in the evaluation of the reliability of the BES. Does this mean the PC perform category ‘D’ [per TPL-004 table 1] analysis for each transfer considered? It is recommended that the standard better spell out the minimum criteria used to limit the transfer. Finally, R2 – R5 have the PC distribute the methodology, assessment and assessment data beyond that which is necessary. Dissemination should be “on request.” While this standard supports reliability through an increase in awareness, other standards, applicable to the PC, ensure the entity has a “Plan” which ensures reliability. As this amounts to a sensitivity study as part of the annual TPL based assessments the VSLs should be reduced.
Response: The SDT believes the VSLs are appropriate. The commenter appears to be referring to VRFs. FAC-013-2 has been written to provide flexibility to the Planning Coordinator to perform the assessment according to their knowledge of the behavior and needs of their system. The SDT does not believe it is appropriate to specify load level, contingency events, nor cut off factors to be used in the assessment. The SDT believes it is essential that adjacent Planning Coordinators be provided the assessment result. Dissemination on request does apply to other reliability related entities.				
Jason L Marshall	Midwest ISO, Inc.	2	Negative	Missing one of the parts 1.1, 1.2, 1.3 or 1.5 is a Moderate VSL while missing only part of 1.4 is a Lower VSL. This implies that missing one of the parts 1.1, 1.2, 1.3 or 1.5 are deemed to have missed a greater part of the requirement as a whole than missing part of 1.4. We disagree and, thus, recommend that the VSLs for missing one of 1.1, 1.2, 1.3 or 1.5 should start at a Lower VSL and increment to the next VSL for each successive missing part.
James D Burley	Midwest Reliability Organization	10	Negative	
Response: The SDT believes the existing VSLs are correct and logical and follow NERC’s guidance on VSL’s for requirements with parts that contribute unequally to the requirement: If a requirement has several parts, and the parts contribute unequally to the reliability-related objective of the requirement, then noncompliance with each of the parts should be clearly associated with at least one of the VSLs. Missing one or two parts of R1.4 is not as significant as missing all of 1.1, 1.2, 1.3. or 1.5. The SDT revised the format of the VSLs for R1 to improve this clarity.				
Robert Mattey	Ohio Valley Electric Corp.	1	Negative	VSLs don't take into account the impact of each of the sub-requirements. Not all sub-requirements are of equal importance but VSLs are based on a number of sub-requirements that are not met without taking into account the reliability impact of the particular sub-requirement.

Balloter	Entity	Segment	Vote	Comment
Response: The SDT deliberated over the VSLs and did assign them based, as you suggest, on their assessment of the contribution that each "part" of the requirement makes to the whole requirement. In the SDT's assessment, missing part of 1.4 has a lesser impact on meeting the intent of the requirement than missing a part of 1.1, 1.2, 1.3 or 1.5 – thus the VSLs that were posted for ballot proposed that meeting a part of 1.4 would be a Lower VSL, and missing a part of 1.1, 1.2, 1.3 or 1.5 would be a Moderate VSL. The SDT revised the format of the VSLs for R1 to improve this clarity.				
John C. Collins	Platte River Power Authority	1	Negative	We suggest writing FAC-013-2 as a Transfer Capability methodology only, and let the entities with a need to determine Transfer Capabilities in the Planning Horizon apply the methodology in a Planning Horizon year of their choosing. According to the December 9, 2010 White Paper for FAC-013-2, there is a desire to "add to the portfolio of knowledge for planning for future reliable operation of the BES" and "to identify potential future weaknesses in the system." We suggest a Transfer Capability assessment belongs in the new draft TPL-001-2 where it could be studied in one of the Near-Term TPL studies, and where past Transfer Capability studies (as qualified in R2.6 of TPL-001-2 Draft 6) would be acceptable under the test for no material changes in the system (don't force an annual assessment).
Terry L Baker	Platte River Power Authority	3	Negative	
Carol Ballantine	Platte River Power Authority	6	Negative	
Response: The SDT does not believe that writing the standard so that it only includes a transfer capability "methodology" would not meet the intent of the directives issued in Order 729. In the future, the requirement to conduct a planning transfer capability assessment may be moved into another standard, but to meet the deadline of filing a standard by January 28, 2010, the SDT believes that the most expeditious way of meeting the FERC deadline was to develop the proposed requirements in the revised FAC-012 standard.				
Henry E. LuBean	Public Utility District No. 1 of Douglas County	4	Negative	Since I voted NO for the 2010-10 standard, I thought it was appropriate to vote no on this ballot to be consistent. The reason I used for the NO vote on the standard is: We agree with others that there is a conflict between the purpose statement and the title of the standard, as well as a concern regarding the potential for double jeopardy given that the requirements of the proposed FAC-013-2 are duplicative with other standards. We suggest, along with others, that it would be more appropriate to incorporate the requirement of this proposed standard into the appropriate section of FAC-010, FAC-014, and the TPL Planning Standards.
Response: The SDT does not believe that there is a conflict between the purpose statement and the requirements – and does not believe that the requirements in the proposed standard duplicate requirements in other standards. Note, however, that the team did rearrange the text within the purpose statement to improve the alignment between the purpose statement and the associated requirements.				
Greg Lange	Public Utility District No. 2 of Grant County	3	Negative	If we don't believe the standard is neccessary then we can't vote for the VSL's.
Response: The ERO has been directed to make changes to the standard to comply with a FERC directive. Most stakeholders who participated in the comment periods for the revision of FAC-012 and FAC-013 indicated support for this project. FERC Order 729 determined in paragraph 290 that the assessment of transfer capability "will be useful for long-term planning, in general, by measuring sufficient long-term capacity needed to ensure the reliable operation of the Bulk-Power System." The standard drafting team is charged with addressing FERC's directives to the ERO and has sought to find an equally effective and efficient means to meet FERC's directive - while maximizing the benefit to reliable transmission system planning.				

Balloter	Entity	Segment	Vote	Comment
Anthony E Jablonski	ReliabilityFirst Corporation	10	Negative	ReliabilityFirst thanks the SDT for making changes to the VSLs based on the prevous comments, but still has concerns with the VSL designations for R2, R3 and R5. The designation of number of days is not inclusive. For example, what if and entity notified one or more of the parties specified in Requirement R2 of a new or revise Transfer Capability Methodology exactly 30 days after its implementaion. Falling exactly at 30 days is "not more than 30 calendar days..." so it is not a Lower VSL. Falling exactly at 30 days is not "more than 30 calendar days" either, thus not a Moderate VSL. The SDT should condiser revising the language to state: "more than or equal to 30 calendar days after its implementation..." within the Moderate, High and Severe VSLs. Please note the emphasis on the words "or equal to".
Response: The entity that was 30 days late would fall into the "not more than 30" and is a Lower VSL. The Lower VSL for R2 should have started with 60 days, and this correction has been made.				
Keith V. Carman	Tri-State G & T Association, Inc.	1	Negative	Tri-State's has submitted comments to support the negative vote through the electronic form provided on the Project 2010-10 Standards page.
Response: Please see the drafting team's response to the comments submitted through the comment form.				
Janelle Marriott	Tri-State G & T Association, Inc.	3	Negative	"Reference Tri-State Generation and Transmission Assn., Inc. Formal comments submitted to NERC electronically via the Project 2010-10 FAC Order 729 Formal Comment link."
Response: Please see the drafting team's response to the comments submitted through the comment form.				

Consideration of Comments on Initial Ballot — Project 2010-10 – FAC Order 729

Successive Ballot Period: 12/30/2010 - 1/8/2011

Summary Consideration:

Some balloters proposed modifications to provide greater clarity, and the following were adopted. Note that none of the modifications changed the scope, intent, or applicability of any of the requirements:

- Moved the definition of "Year One" from Project 2006-02 to this project for complete clarity on the time period associated with the requirements
- Modified the purpose statement to better align with the requirements
- Changed "Methodology" to "methodology throughout the standard
- Added "long-term" to clarify the scope of outages that must be addressed in the methodology
- Clarified that R2, Part 2.2 is limited to distribution of the methodology; added language to R5 to clarify that the assessment results must be shared with entities that have a reliability-related need for the information, but confidential information is protected.
- Added a statement to R6 to clarify that entities are not required to share confidential data
- Rephrased the VSLs for R1 to improve clarity
- Corrected the VSLs for R2 (these had set the lower VSL at a level that described acceptable performance)

If you feel that the drafting team overlooked your comments, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Herb Schrayshuen, at 609-452-8060 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

Balloter	Entity	Segment	Vote	Comment
Mark B Thompson	Alberta Electric System Operator	2	Negative	R6 is an unnecessary administrative requirement that provides no reliability benefit. It attempts to implement the open access concepts of transparency and comparability by allowing a third party to repeat or mimic the Planning Coordinator's calculations. It is strictly a commercial issue and simply does not belong in enforceable reliability standards. Further, it presumes that the Planning Coordinator is not able to perform its function and that compliance monitoring and enforcement processes of NERC and the Regional Entities will not detect deficiencies which will result in mitigation plans to correct deficiencies. Furthermore, some entities simply cannot have the data without violating FERC standards of conduct and data confidentiality policies.
Response: R6 serves a reliability purpose; it provides sufficient data for those entities with a reliability related requirement to verify data, to verify assumptions and to validate assessments.				
Jennifer Richardson	Ameren Energy Marketing Co.	6	Negative	(1) R1.4.3 should be modified to be System demand, including but not limited to forecast peak demand and appropriate load distribution.

[1] The appeals process is in the Reliability Standards Development Procedure: http://www.nerc.com/files/RSDP_V6_1_12Mar07.pdf.

<table>
<tr><th>Balloter</th><th>Entity</th><th>Segment</th><th>Vote</th><th>Comment</th></tr>
<tr><td>Kirit S. Shah</td><td>Ameren Services</td><td>1</td><td>Negative</td><td>(2)R1.4.6 should be limited to single contingency events for the transfer capability values to have meaning. System performance deficiencies for multiple contingency events can be mitigated by dropping of system load under the existing TPL standards.

(3)R1.4.8 should be added to cover distribution factor cutoff assumptions.

(4)The Purpose statement should be modified to include that Transfer capability is not a single value and is dependent on the selection and participation of sources and sinks on the defined transmission system. A multitude of assumptions goes into the development of the power system model, and the transfer capability study/assessment assumptions need to be discussed and documented.

(5)As one of the benefits of transfer capability testing and analysis is tracking/trending. Therefore, a definition also need to be developed and included for Long-Term Transmission Planning Horizon. This would allow comparison of transfer capabilities in the near-term as well as long-term planning horizons.</td></tr>
<tr><td colspan="5">Response: FAC-013-2 has been written to provide flexibility to the Planning Coordinator to perform the assessment according to their knowledge of the behavior and needs of their system. The SDT does not believe it is appropriate to specify load level, contingency events, nor cut off factors to be used in the assessment.</td></tr>
<tr><td>Steven Norris</td><td>APS</td><td>3</td><td>Negative</td><td rowspan="4">1) FAC-013-2 appears to duplicate assessment study work required in MOD-001. The MOD-001, MOD-028, MOD-029, and MOD-030 standards essentially require that entities have a methodology and perform an Available Transfer Capability Assessment, with potential of also having to perform a Total Transfer Capability assessment, with no defined date-range which, for some utilities, will be up to 10 years. FAC-013-2 requires entities perform a Transfer Capability assessment for years 1-5, thereby making FAC-013-2 a duplicative process.

2) It is not clear if an entity would have to perform yearly TTC studies for all paths or whether an entity could access each path yearly and determine if a need existed for a restudy of the TTC for a particular path.</td></tr>
<tr><td>Mel Jensen</td><td>APS</td><td>5</td><td>Negative</td></tr>
<tr><td>Robert D Smith</td><td>Arizona Public Service Co.</td><td>1</td><td>Negative</td></tr>
<tr><td>Justin Thompson</td><td>Arizona Public Service Co.</td><td>6</td><td>Negative</td></tr>
<tr><td colspan="5">Response: The SDT recognizes that FAC-013-2 may use the same study work that is used in MOD-029-1; that would not be true for entities that use MOD-028-1 and MOD-030-2. Regardless, the methodologies in the MOD standards DO have a defined date range (the Operations Planning horizon). FAC-013-2 has a different date range (the Near-term Planning horizon). Therefore the standards are not duplicative for WECC and definitively not duplicative for non-WECC entities; even if some of the study work is the same study work that is used in MOD-029-1. FAC-013-2 has been written to provide flexibility to the Planning Coordinator to perform the assessment according to their knowledge of the behavior and needs of their system. The MOD Standards do not afford such flexibility</td></tr>
</table>

Balloter	Entity	Segment	Vote	Comment
Venkataramakrishnan Vinnakota	BC Hydro	2	Negative	The SDT is to be commended for their efforts to respond to FERC directions and input from NERC members to combine the standards FAC-012 and FAC-013 in to a single document to cover transfer capabilities in the planning horizon. However, BC Hydro is voting no on this ballot. Based on existing standards BC Hydro has already established transfer capability and SOL methodologies for both the operating and planning horizons under the existing FAC-010 - 013 standards. We believe there is no value added in the creation of new terminology and processes used to calculate Planning Transfer Capabilities. The introduction of this new terminology and possibly new processes to determine PTCs may undermine efforts taken by utilities to become compliant with the existing standards, introduces duplication and potential for confusion, and ultimately detract from the common goals of increased reliability.
Pat G. Harrington	BC Hydro and Power Authority	3	Negative	
Clement Ma	BC Hydro and Power Authority	5	Negative	
Gordon Rawlings	BC Transmission Corporation	1	Negative	
Response: The SDT recognizes that FAC-013-2 may use some of WECC's required efforts in FAC-010, FAC-014, and the TPL Planning Standards TPL-001 through TPL-004; that would not necessarily be true for entities outside of WECC. Regardless, the methodology in FAC-013-2 has a different date range (the Near-term Planning horizon). Therefore the standards are not completely duplicative for WECC and definitively not duplicative for non-WECC entities; even if some of the effort is the same work that is used in other standards. FAC-013-2 has been written to provide flexibility to the Planning Coordinator to perform the assessment according to their knowledge of the behavior and needs of their system. The MOD and TPL Standards do not afford such flexibility.				
Donald S. Watkins	Bonneville Power Administration	1	Negative	Please refer to BPA formal comments submitted on 1/7/11
Rebecca Berdahl	Bonneville Power Administration	3	Negative	
Francis J. Halpin	Bonneville Power Administration	5	Negative	
Response: Please refer to response to comments in Consideration of Comments on FAC-013-2				
Gregory Van Pelt	California ISO	2	Negative	Reference the IRC Standards Review Committee Comments. Also Reference the WECC comments in their recommendation and note that while we generally agree with the WECC in that improvements have been made, we do not agree in approving a standard with known deficiencies or conflicts. Neither do we agree with adding the Requirement 6.
Response: Please refer to response to comments in Consideration of Comments on FAC-013-2				
Chang G Choi	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	1	Negative	Based on our analysis of the proposed FAC-013-2 revisions and subsequent discussions, Tacoma Power is voting Negative on the FAC-013-2 ballot for the following reasons: 1) The currently balloted standard & requirements should apply to RC and/or entities

<table>
<tr><th>Balloter</th><th>Entity</th><th>Segment</th><th>Vote</th><th>Comment</th></tr>
<tr><td>Max Emrick</td><td>City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power</td><td>5</td><td>Negative</td><td>with major, critical transfer paths, not a system that is primarily a load serving system. We think the existing FAC-012-1 & FAC-013-1 describe the applicability with appropriate clarity. The revision should retain the applicability provisions as they exist in the existing standards FAC-012-1 & FAC-013-1.

2) We believe all the requirements in the balloted standard are duplicative and are already covered by the requirements in TPL-001 thru TPL-004, FAC-010, & FAC-014. Therefore, this created a possibility for multiple fines on a single offense. It is not best practices to substantially repeat requirements from other standards, difficulties with subsequent revisions in multiple standards, and concerns about double-jeopardy.

3) Lastly, the revision is written too ambiguous and subject to multiple interpretations. Thank you for your consideration.</td></tr>
<tr><td colspan="5">Response: 1.The applicability was assigned to the PC because of their generally wider area view and to be in accord with a FERC directive.

2. The SDT recognizes that FAC-013-2 may use some of WECC's required efforts in FAC-010, FAC-014, and the TPL Planning Standards TPL-001 through TPL-004; that would not necessarily be true for entities outside of WECC. Regardless, the methodology in FAC-013-2 has a different date range (the Near-term Planning horizon). Therefore the standards are not completely duplicative for WECC and definitively not duplicative for non-WECC entities; even if some of the effort is the same work that is used in other standards. FAC-013-2 has been written to provide flexibility to the Planning Coordinator to perform the assessment according to their knowledge of the behavior and needs of their system. The MOD and TPL Standards do not afford such flexibility.

3. The comment lacks sufficient specificity for the SDT to render a response.</td></tr>
<tr><td>Paul Morland</td><td>Colorado Springs Utilities</td><td>1</td><td>Negative</td><td>We suggest writing FAC-013-2 as a Transfer Capability methodology only, and let the entities with a need to determine Transfer Capabilities in the Planning Horizon apply the methodology in a Planning Horizon year of their choosing. According to the December 9, 2010 White Paper for FAC-013-2, there is a desire to "add to the portfolio of knowledge for planning for future reliable operation of the BES" and "to identify potential future weaknesses in the system." We suggest a Transfer Capability assessment belongs in the new draft TPL-001-2 where it could be studied in one of the Near-Term TPL studies, and where past Transfer Capability studies (as qualified in R2.6 of TPL-001-2 Draft 6) would be acceptable under the test for no material changes in the system</td></tr>
<tr><td colspan="5">Response: 1.The SDT believes the Standard is consistent with your comments and applies to the Near Term Planning Horizon.

2. The SDT does not disagree that it may be appropriate to move the requirements of FAC-013-2 into the TPL standards at some time in the future.</td></tr>
<tr><td>Christopher L de Graffenried</td><td>Consolidated Edison Co. of New York</td><td>1</td><td>Negative</td><td rowspan="2">See detailed comments submitted to NERC website</td></tr>
<tr><td>Peter T Yost</td><td>Consolidated Edison Co. of New</td><td>3</td><td>Negative</td></tr>
</table>

Balloter	Entity	Segment	Vote	Comment
	York			
Wilket (Jack) Ng	Consolidated Edison Co. of New York	5	Negative	
Nickesha P Carrol	Consolidated Edison Co. of New York	6	Negative	
Response: Please refer to response to comments in Consideration of Comments on FAC-013-2				
Henry Ernst-Jr	Duke Energy Carolina	3	Affirmative	Duke Energy appreciates the work of the drafting team and offers the following clarifying changes for further improvement to the standard. 1. Adoption of the Near-Term Transmission Planning Horizon definition from the TPL-001-2 standard development will also require adoption of the definition of Year One which is part of the Near-Term Transmission Planning Horizon definition. 2. The VSLs for R2 are incorrect. The paragraph after the “OR” in the Lower VSL is not a violation. To correct this, replace the paragraph after the “OR” in the Lower VSL with the corresponding paragraph from Moderate. Likewise, move the paragraph after the “OR” in Higher to Moderate. Also, modify the paragraph after the “OR” in High to make it 90 to 120 days. Then add a new paragraph after the “OR” in Severe, making it more than 120 days after receipt of a request. 3. As written, R2.2 is hard to follow. Suggest rewriting as follows: “Distribute the results of the annual assessment of Transfer Capabilities to any other functional entity that has a reliability-related need, within 30 days of receiving a written request.” 4. As written, R4 could possibly allow the Planning Coordinator to conduct an assessment based on a simulation that has not been updated. We believe the intent was to require a simulation to be performed each calendar year and assessment conducted based on that simulation. To clarify the intent, suggest rewriting as follows: “During each calendar year, each Planning Coordinator shall conduct simulations and document an assessment based on those simulations in accordance with its Transfer Capability Methodology for at least one year in the Near-Term Transmission Planning Horizon.”
Response: 1. The SDT agrees and has made the suggested changes. 2. The SDT agrees and has made the suggested changes. 3. R2.2 The SDT agrees with the intent of the proposed language and has incorporate it into the standard – R2, Part 2.2 was modified to clarify that this is requiring distribution of the methodology to entities with a reliability-related need for this; R5 was modified to clarify that the assessment results must be				

Balloter	Entity	Segment	Vote	Comment
shared with entities that have a reliability-related need for that information, subject to confidentiality rules. 4. R4. The SDT agrees with the proposed language in R4 and will incorporate it into the standard				
Frank Gaffney	Florida Municipal Power Agency	4	Negative	Although the Standard Drafting Team (SDT) has made very significant improvements to the standard, there are a few items that ought to be "fixed". * R2 is confusing. The main requirement requires distribution of the methodology; however, bullet 2.2 requires distribution of the results. Which is it? It would seem bullet 2.2 needs to be redrafted to refer to the methodology since the distribution of results is in R5. * R5 needs more clarity. It says that the PC must make the results available, but to whom? Due to CEII, we presume this is not for publishing on a web-site, so, we presume that the recipients would be the same as in R2, but, R5 should specifically say so. Would it make sense to move R4 to before R2 and combine R2 with R5 , and R3 with R6 and have R2/R5 and R3/R6 refer to both the methodology and results?
David Schumann	Florida Municipal Power Agency	5	Negative	
Richard L. Montgomery	Florida Municipal Power Agency	6	Negative	
Thomas W. Richards	Fort Pierce Utilities Authority	4	Negative	
Stan T. Rzad	Keys Energy Services	1	Negative	
Response: R2 - Thank you for your comments. R2.2 requires the distribution of the Planning Coordinator's Transfer Capability Methodology, not the assessment results. The SDT clarified the intent by modifying Part 2.2 to require distribution of the methodology to entities that have a reliability-related need for the methodology and modified R5 to clarify that the assessment results must be shared with entities that have a reliability-related need for the information, subject to confidentiality rules. R5. Each Planning Coordinator shall make the documented Transfer Capability assessment results available within 45 calendar days of the completion of the assessment to the recipients of its Transfer Capability Methodology pursuant to R2.1 and R2.2. However, if a functional entity that has a reliability related need for the results of the annual assessment of the Transfer Capabilities makes a written request for such an assessment after the completion of the assessment, the Planning Coordinator shall make the documented Transfer Capability assessment results available to that entity within 45 calendar days within receipt of the request Move R4 to before R2 and combine R2 with R5: The SDT believes the current ordering provides the best clarity. R1, R2 and R3 deal with the methodology and R4, R5 and R6 deal with the assessment.				
Joseph S. Stonecipher	Beaches Energy Services	1	Negative	Although the Standard Drafting Team (SDT) has made very significant improvements to the standard, there are a few items that ought to be "fixed": 1. The definition now reads "The transmission planning period that covers year's one through five." Is "year one" the current year or the next year, e.g., doing a study in 2011, is "year one" 2011 or 2012? 2. "R2" is confusing: The main requirement requires distribution of the methodology; however, bullet 2.2 requires distribution of the results. Which is it? It would seem bullet 2.2 needs to be redrafted to refer to the methodology since the distribution of

Balloter	Entity	Segment	Vote	Comment
				results is in R5. 3. R5 needs more clarity. It says that the PC must make the results available, but to whom? Due to CEII, we presume this is not for publishing on a web-site, so, we presume that the recipients would be the same as in R2, but, R5 should specifically say so. Would it make sense to move R4 to before R2 and combine R2 with R5 , and R3 with R6 and have R2/R5 and R3/R6 refer to both the methodology and results? Anyway, this Standard needs some more work on it.
Response: 1. The definition of Year One from the **draft** TPL-001-2 standard, which is used in the Near-Term Transmission Planning Horizon definition, will also be adopted in this standard which clarifies the assessment period. 2. R2 - Thank you for your comments. R2.2 requires the distribution of the Planning Coordinator's Transfer Capability Methodology, not the assessment results. The SDT clarified the intent by modifying Part 2.2 to require distribution of the methodology to entities that have a reliability-related need for the methodology and modified R5 to clarify that the assessment results must be shared with entities that have a reliability-related need for the information, subject to confidentiality rules. 3. R5. Each Planning Coordinator shall make the documented Transfer Capability assessment results available within 45 calendar days of the completion of the assessment to the recipients of its Transfer Capability Methodology pursuant to R2.1 and R2.2. However, if a functional entity that has a reliability related need for the results of the annual assessment of the Transfer Capabilities makes a written request for such an assessment after the completion of the assessment, the Planning Coordinator shall make the documented Transfer Capability assessment results available to that entity within 45 calendar days within receipt of the request				
Gregg R Griffin	City of Green Cove Springs	3	Negative	R2 is confusing. The main requirement requires distribution of the methodology; however, bullet 2.2 requires distribution of the results. Which is it? It would seem bullet 2.2 needs to be redrafted to refer to the methodology since the distribution of results is in R5. R5 needs more clarity. It says that the PC must make the results available, but to whom? Due to CEII, we presume this is not for publishing on a web-site, so, we presume that the recipients would be the same as in R2, but, R5 should specifically say so. Would it make sense to move R4 to before R2 and combine R2 with R5 , and R3 with R6 and have R2/R5 and R3/R6 refer to both the methodology and results?
Response: R2 - Thank you for your comments. R2.2 requires the distribution of the Planning Coordinator's Transfer Capability Methodology, not the assessment results. The SDT clarified the intent by modifying Part 2.2 to require distribution of the methodology to entities that have a reliability-related need for the methodology and modified R5 to clarify that the assessment results must be shared with entities that have a reliability-related need for the information, subject to confidentiality rules.				

Balloter	Entity	Segment	Vote	Comment
R5. Each Planning Coordinator shall make the documented Transfer Capability assessment results available within 45 calendar days of the completion of the assessment to the recipients of its Transfer Capability Methodology pursuant to R2.1 and R2.2. However, if a functional entity that has a reliability related need for the results of the annual assessment of the Transfer Capabilities makes a written request for such an assessment after the completion of the assessment, the Planning Coordinator shall make the documented Transfer Capability assessment results available to that entity within 45 calendar days within receipt of the request Move R4 to before R2 and combine R2 with R5: The SDT believes the current ordering provides the best clarity. R1, R2 and R3 deal with the methodology and R4, R5 and R6 deal with the assessment.				
Lee Schuster	Florida Power Corporation	3	Negative	The proposed definition for "Near-Term Transmission Planning Horizon" is "The transmission planning period that covers years one through five." This proposed definition is confusing in that the part "...covers year[s] one..." appears to overlap the operating time frame. The definition should be revised back to "...beyond 13 months..." to clarify when the Near-Term Transmission Planning Horizon starts.
Response: 1. The definition of Year One from the **draft** TPL-001-2 standard, which is used in the Near-Term Transmission Planning Horizon definition, will also be adopted in this standard which clarifies the assessment period.				
Ajay Garg	Hydro One Networks, Inc.	1	Negative	Hydro One is casting a negative with the following comments: 1. We thank the SDT for responding positively to the industry comments to remove the two terms Planning Transfer Capability and Planning Transfer Capability Methodology Document, and insert the appropriate wording into the requirements. 2. However, the term "Transfer Capability Methodology" appears capitalized, implying that this is a defined term but this term is neither defined in the NERC Glossary nor being proposed in the standard as a new term. We note that this term is currently used in both FAC-012-1 and used in FAC-013-1 although not included in the NERC glossary. 3. We do not have a concern with using this term to indicate that it is a documented methodology for use in performing an annual assessment of Transfer Capability in the Near-Term Transmission Planning Horizon, but it needs to be changed to lower case; or else this term needs to be defined. Our preference is lower case. 4. Additionally, although we support the intent of Requirement R6 we suggest that it be revised to provide for the protection of the confidentiality of information and the PC's obligations, as follows: "If a recipient of a documented Transfer Capability assessment requests data to support the assessment, the Planning Coordinator shall provide such data to that entity within 45 calendar days of receipt of the request
David L Kiguel	Hydro One Networks, Inc.	3	Negative	

Balloter	Entity	Segment	Vote	Comment
				subject to the condition of established information confidentiality agreements in place.”
Response: 2 & 3. Agree. The SDT changed the capitalized word, “Methodology” to non-capitalized throughout the standard. 4. Because of concerns regarding restrictions on dissemination of CEII and commercially sensitive information, R6 has been reworded as “If a recipient of a documented Transfer Capability assessment requests data to support the assessment results, the Planning Coordinator shall provide such data to that entity within 45 calendar days of receipt of the request. The provision of such data shall be subject to the legal and regulatory obligations of the Planning Coordinator’s area regarding the disclosure of confidential and/or sensitive information.”				
Kim Warren	Independent Electricity System Operator	2	Negative	We thank the SDT for your positive response to industry comments regarding Standard FAC-013-2, namely: by removing the terms “PTC” and “PTCMD” and by adding language that more appropriately addresses the calculation of Transfer Capability in the Near-Term Transmission Planning Horizon. The IESO submits two final matters requiring the SDT’s consideration. First, the IESO is concerned that the term “Transfer Capability Methodology”, which appears to be defined in the Standard (and is also currently used in FAC-012-1 and FAC-013-1), is not a defined term in the NERC glossary. The IESO recommends that the term “Transfer Capability Methodology” either be added to the NERC glossary, or modified in FAC-013-2 such that the word “methodology” is written entirely in lower case lettering. The latter approach would be consistent with that used in the recently approved standard PRC-006-1, where the description “UFLS entities” was established and used within the standard to avoid long-winded requirements that repeatedly refer to the same entities. Second, while the IESO generally supports the underlying rationale for Requirement R6, it must be further revised to respect the reality of there being differing (and potentially conflicting) data confidentiality provisions and regulatory environments across North America. The IESO recommends that an additional statement be added to Requirement R6, to the following effect: “Upon receiving a request by a recipient of a documented Transfer Capability assessment for data in support the assessment, a

Balloter	Entity	Segment	Vote	Comment
				Planning Coordinator shall provide the requestor with such data within 45 calendar days. Notwithstanding the foregoing sentence, the provision of such data shall be subject to the legal and regulatory obligations of the Planning Coordinator's area regarding the disclosure of confidential and/or sensitive information."
Response: 1. The SDT changed the capitalized word, "Methodology" to non-capitalized throughout the standard. 2. Because of concerns regarding restrictions on dissemination of CEII and commercially sensitive information, R6 has been reworded as "If a recipient of a documented Transfer Capability assessment requests data to support the assessment results, the Planning Coordinator shall provide such data to that entity within 45 calendar days of receipt of the request. The provision of such data shall be subject to the legal and regulatory obligations of the Planning Coordinator's area regarding the disclosure of confidential and/or sensitive information."				
Michael Moltane	International Transmission Company Holdings Corp	1	Negative	As written, the standard should be changed to a NERC "guideline" or white paper. While it does "standardize" the calculation of transfer capabilities in that certain data must be considered, it does not put any bounds on the data selected by the PC for these studies. More importantly, the annual requirement for studies does not have any obligation to do anything with the results. If corrective actions were mandated, then a "requirement" would make sense. Without any requirement for corrective action, this standard is not meaningful.
Response: The comments indicate that the standard is believed to be unnecessary for reliable planning. FERC Order 729 addressed the need for the standard and determined in paragraph 290 that the assessment of transfer capability "will be useful for long-term planning, in general, by measuring sufficient long-term capacity needed to ensure the reliable operation of the Bulk-Power System." The standard drafting team is charged with addressing FERC's directives to the ERO and has sought to find an equally effective and efficient means to meet FERC's directive - while maximizing the benefit to reliable transmission system planning.				
Kathleen Goodman	ISO New England, Inc.	2	Negative	Please refer to the comments submitted.
Response: Please refer to response to comments in Consideration of Comments on FAC-013-2				
Larry E Watt	Lakeland Electric	1	Negative	1. This standard requires further clarification. This clarification should be within the standard, not in the associated white paper. 2. This standard is unnecessary to meet the reliability needs of the BPS.
Paul Shipps	Lakeland Electric	6	Negative	

Balloter	Entity	Segment	Vote	Comment
Response: Comment 1 does not specify what element requires further clarification so the SDT is unable to respond. 2. The comments indicate that the standard is believed to be unnecessary for reliable planning. FERC Order 729 addressed the need for the standard and determined in paragraph 290 that the assessment of transfer capability "will be useful for long-term planning, in general, by measuring sufficient long-term capacity needed to ensure the reliable operation of the Bulk-Power System." The standard drafting team is charged with addressing FERC's directives to the ERO and has sought to find an equally effective and efficient means to meet FERC's directive - while maximizing the benefit to reliable transmission system planning.				
Mace Hunter	Lakeland Electric	3	Negative	FAC-013-2 lacks clarity, its VSLs are severe for what amounts to a long range sensitivity study, and the requirements should better match the purpose. The whitepaper adds some clarity; however, the clarity should be in the standard, not in associated white papers. It is unclear if the intent is to have the PC determine the amount of internal generation that can be replaced with external generation or if the PC should determine system upgrades using Transfer Capability as a consideration. These two studies would be approached differently and give different results. There are many reasons, beyond the two discussed, to perform TC determination. Recommend better refining of the purpose of the Transfer Capability Assessment to be performed. An example of a requirement that requires clarification: Requirement R1, Part R1.3 "A statement that the assumptions and criteria used to perform the assessment are consistent with the Planning Coordinator's planning practices.", is intended to provide consistency in the performance of the assessment of transfer capability and the planning practices used in the evaluation of the reliability of the BES. Does this mean the PC perform category 'D' [per TPL-004 table 1] analysis for each transfer considered? It is recommended that the standard better spell out the minimum criteria used to limit the transfer. Finally, R2 – R5 have the PC distribute the methodology, assessment and assessment data beyond that which is necessary. Dissemination should be "on request." While this standard supports reliability through an increase in awareness, other standards, applicable to the PC, ensure the entity has a "Plan" which ensures reliability. As this amounts to sensitivity study as part of the annual TPL based assessments the VSLs should be reduced.
Response: The SDT believes the VSLs are appropriate. The commenter appears to be referring to VRFs. FAC-013-2 has been written to provide flexibility to the Planning Coordinator to perform the assessment according to their knowledge of the behavior and needs of their system. The SDT does not believe it is appropriate to specify load level, contingency events, nor cut off factors to be used in the assessment.				

Balloter	Entity	Segment	Vote	Comment
The SDT believes it is essential that adjacent Planning Coordinators be provided the assessment result. Dissemination on request does apply to other reliability related entities.				
Charles A. Freibert	Louisville Gas and Electric Co.	3	Negative	Comment on Project 2010-10 Negative Ballot LG&E and KU Energy continue to oppose the proposal. The Standard Drafting Team while making change from their last proposal, (which only received a 40 percent approval level), still failed to address several recommendations from commenters. The comments made by several parties but were dismissed by the SDT include: - The proposal is duplicative of already in place standards dealing with future transmission planning processes, - The standard requirements for stakeholder participations are already embedded in the Order 890 OATTs of participants. - Meeting the proposed requirements may be burdensome for participants and at the same time not enhance BES reliability
Response: FERC Order 729 addressed the need for the standard and determined in paragraph 290 that the assessment of transfer capability "will be useful for long-term planning, in general, by measuring sufficient long-term capacity needed to ensure the reliable operation of the Bulk-Power System." The standard drafting team is charged with addressing FERC's directives to the ERO and has sought to find an equally effective and efficient means to meet FERC's directive - while maximizing the benefit to reliable transmission system planning.				
Terry Harbour	MidAmerican Energy Co.	1	Negative	The purpose and applicability of this standard should be assigned to the Transmission Service Provider since the assessment seems to deal with the analysis of system power transfers above approved firm transfers already accounted for in the existing TPL models and assessments.
Response: The purpose of the standard is to focus more on the limiting facilities that are identified under the stress of specific energy transfers. Changes in energy transfers can occur for a variety of reasons (change in resource plans, changes in energy costs, new generation sources,..) and understanding the potential impact on facilities, (and thus reliability), is important to effective transmission planning. This is the responsibility of the Planning Coordinator not the TSP.				
Jason L Marshall	Midwest ISO, Inc.	2	Negative	While the standard represents an improvement by allowing the transfer capability to be calculated in year 1 and not years 2-5, we still generally disagree with the purpose. Transfer capabilities in the planning horizon are not useful for the reliable planning of the transmission system and/or any expansion plans. The current, approved TPL standards already provide system expansion requirements to assure reliable system performance with regard to firm transfer commitments, but not to limits that may exceed those firm commitments such as those that would be indicated in PTC calculations. Further, it must be noted that there are no TPL standards that require system expansion for maintenance of transfer capabilities above firm transfer commitments. As such, transfer capabilities in the planning horizon provide no additional information that can be used for system planning. In addition, transfer capabilities calculated 2 to 5 years ahead are not useful to give system operators advance warning or appropriate, applicable operating limits because operating horizon conditions will be significantly

Balloter	Entity	Segment	Vote	Comment
				different than those projected during the planning horizon (2 to 5 years previously). R6 is an unnecessary administrative requirement that provides no reliability benefit. It attempts to implement the open access concepts of transparency and comparability by allowing a third party to repeat or mimic the Planning Coordinator's calculations. It is strictly a commercial issue and simply does not belong in enforceable reliability standards. Further, it presumes that the Planning Coordinator is not able to perform its function and that compliance monitoring and enforcement processes of NERC and the Regional Entities will not detect deficiencies which will result in mitigation plans to correct deficiencies. Furthermore, some entities simply cannot have the data without violating FERC standards of conduct and data confidentiality policies. For bullet 1.2, do only the SOLs in the planning horizon governed by FAC-011-2 apply or do those in the operating horizon also apply? Since the standard applies to the planning horizon, it should only be planning SOLs. Furthermore, this bullet is administrative in nature and should be modified. A statement that SOLs shall be respected provides no reliability value. How does an entity prove compliance with R3? How does it prove it did not receive comments from a recipient of the methodology? R3 should be removed from the standard as it is an administrative requirement that is unnecessary, contrary to the results-based standards. What value does it provide other than to make third parties feel like they can force a response to their input? Transfer capability calculations have been performed for so long and are so well understood by industry, it is hard to fathom a third party providing any valuable technical input that a Planning Coordinator has not already considered. This requirement presumes that the Planning Coordinator may not be capable of performing the function for which they are registered and certified. It further presumes that NERC and Regional Entities' Compliance Monitoring and Enforcement Processes will not be able to identify deficiencies with complying with Requirement R1. Furthermore, the requirement to respond to all technical comments and/or revise the methodology would be a significant administrative burden to the Planning Coordinators. Part 2.2 should be either be removed due to its subjective nature or criteria for requesting such data should be added to clarify what entities can request such data, under what circumstances they can do so, and how disputes regarding such requests are to be resolved. More specifically, R3 contains no indication regarding the entity that makes the determination that a functional entity had a reliability-related need to the results of the annual assessment of Transfer Capabilities. In R1, the term Transfer Capability Methodology is used and capitalized. It does not have a current definition in the NERC glossary and the SDT did not propose a

Balloter	Entity	Segment	Vote	Comment
				definition. It should be defined or made lower case.

Response:

The purpose of the standard is to focus **more** on the limiting facilities that are identified under the stress of specific energy transfers, rather than the specific values. Changes in energy transfers can occur for a variety of reasons (change in resource plans, changes in energy costs, new generation sources,..) and understanding the potential impact on facilities, (**and thus reliability**), is important to effective transmission planning. The SDT does not disagree that it may be appropriate to move the requirements of FAC-013-2 into the TPL standards at some time in the future. FERC Order 729 addressed the need for the standard and determined in paragraph 290 that the assessment of transfer capability "will be useful for long-term planning, in general, by measuring sufficient long-term capacity needed to ensure the reliable operation of the Bulk-Power System." The standard drafting team is charged with addressing FERC's directives to the ERO and has sought to find an equally effective and efficient means to meet FERC's directive - while maximizing the benefit to reliable transmission system planning.

For R1.2, the SOLs could be either the planning horizon or the operating horizon. R1.2 requires a "statement that the assessment shall respect known System Operating Limits (SOLs)." Although the standard applies to the planning horizon, good planning practice may require operating horizon SOLs if the SOLs are known and the SOLs could impact the planning horizon; therefore the SDT does not believe that it should only be planning SOLs. Whether R1.2 is "is administrative in nature" or not, it ensures that Planning Coordinators must include known SOLs or suffer a penalty for not including them. The SDT believes that including known SOLs does have reliability value.

"How does an entity prove compliance with R3?" As stated in M3, "Each Planning Coordinator shall have evidence, such as dated e-mail or dated transmittal letters, that the Planning Coordinator provided a written response to that commenter in accordance with Requirement R3." "How does it prove it did not receive comments from a recipient of the methodology?" In the standard's Data Retention section, "The Planning Coordinator shall retain evidence to show compliance with Requirements R3, R4, R5 and R6 for the most recent assessment." The evidence could include a written attestation before an audit to confirm that it had not received any comments.

The SDT does not believe that "R3 should be removed from the standard as it is an administrative requirement that is unnecessary, contrary to the results-based standards." Requiring the Planning Coordinator to respond to commenters is necessary as it may lead to changes in the methodology; at the very least, it makes the methodology more transparent to all NERC registered functional entities. The SDT does not agree that Planning Transfer Capability methods are well understood or transparent to all NERC registered functional entities that may comment. R3 does not presume "that the Planning Coordinator may not be capable of performing the function for which they are registered and certified" nor does it presume "that NERC and Regional Entities' Compliance Monitoring and Enforcement Processes will not be able to identify deficiencies." It does presume that NERC registered functional entities may need greater transparency on the methodology. It is unclear if R3 "would be a significant administrative burden to the Planning Coordinators." If R3 does become a significant administrative burden to some Planning Coordinators, then it would indicate that their methodology is not transparent to other reliability

Balloter	Entity	Segment	Vote	Comment
related entities.				
James D Burley	Midwest Reliability Organization	10	Negative	The commission has indicated that the FAC-013 should be applicable to Reliability Coordinators. The process and criteria used to determine transfer capabilities must be consistent with the process and criteria used for other users of the Bulk-Power System. Simply stated, the criteria used to calculate transfer capabilities for use in determining ATC must be identical to those used in planning and operating the system. The commission has ruled twice as to the position (Paragraphs 782&785 of the FERC order 693 and the paragraph 278 of the.)The current draft of the standard FAC-013-2 does not reflect the commission's position therefore the MRO has voted negative.
Response: The SDT believes that the FAC-013-02 reflects FERCs current position. Subsequent to FERC order 693, Order 729, at Paragraph 290, FERC directed that FAC 013-02 be applicable to the Planning Coordinator and not the Reliability Coordinator.				
Gregory Campoli	New York Independent System Operator	2	Negative	see comments provided.
Response: Please refer to response to comments in Consideration of Comments on FAC-013-2				
Robert Mattey	Ohio Valley Electric Corp.	1	Negative	Two sub-requirements (1.2 and 1.3) reference the inclusion of "statements" that something will be done. It seems inappropriate to have the inclusion of "statements" as requirements rather than just listing what reliability items must be considered.
Response: Statement such as those referenced are a means of ensuring that required practices are included in the Planning Coordinator's documented methodology.				
John C. Collins	Platte River Power Authority	1	Negative	We suggest writing FAC-013-2 as a Transfer Capability methodology only, and let the entities with a need to determine Transfer Capabilities in the Planning Horizon apply the methodology in a Planning Horizon year of their choosing. According to the December 9, 2010 White Paper for FAC-013-2, there is a desire to "add to the portfolio of knowledge for planning for future reliable operation of the BES" and "to identify potential future weaknesses in the system." We suggest a Transfer Capability assessment belongs in the new draft TPL-001-2 where it could be studied in one of the Near-Term TPL studies, and where past Transfer Capability studies (as qualified in R2.6 of TPL-001-2 Draft 6) would be acceptable under the test for no material changes in the system (don't force an annual assessment).
Carol Ballantine	Platte River Power Authority	6	Negative	
Response: 1.The SDT believes the Standard is consistent with your comments and applies to the Near Term Planning Horizon. 2. The SDT does not disagree that it may be appropriate to move the requirements of FAC-013-2 into the TPL standards at some time in the future. The SDT believes that it is important to run simulations annually to ensure no changes outside the Planning Coordinator's system will impact the assessment result.				

Balloter	Entity	Segment	Vote	Comment
Terry L Baker	Platte River Power Authority	3	Negative	Much confusion between "Transfer Capabilities" and "SOLs" was introduced in the beginning. NERC planned to reduce this confusion by retiring FAC-012 and -013 along with implementation of the new MOD standards. The proposed FAC-013-2 fuels more confusion and is not necessary. We have FAC-010-2.1 that addresses the SOL methodology to be used by those calculating transfer capabilities in the Planning Horizon.
Response: FERC Order 729 addressed these issues and determined in paragraph 290 that the assessment of transfer capability "will be useful for long-term planning, in general, by measuring sufficient long-term capacity needed to ensure the reliable operation of the Bulk-Power System." NERC is charged with addressing FERC's directives and the standard drafting team has sought to find an equally effective and efficient means to meet FERC's directives - while maximizing the benefit to reliable transmission system planning.				
Sammy Roberts	Progress Energy Carolinas	1	Negative	The proposed definition for "Near-Term Transmission Planning Horizon" is "The transmission planning period that covers years one through five." This proposed definition is confusing in that the part "...covers year[s] one..." appears to overlap the operating time frame. The definition should be revised back to "...beyond 13 months..." to clarify when the Near-Term Transmission Planning Horizon starts.
Sam Waters	Progress Energy Carolinas	3	Negative	
Wayne Lewis	Progress Energy Carolinas	5	Negative	
Response: The definition of Year One from the **draft** TPL-001-2 standard, which is used in the Near-Term Transmission Planning Horizon definition, will also be adopted in this standard which clarifies the assessment period.				
Henry E. LuBean	Public Utility District No. 1 of Douglas County	4	Negative	We agree with others that there is a conflict between the purpose statement and the title of the standard, as well as a concern regarding the potential for double jeopardy given that the requirements of the proposed FAC-013-2 are duplicative with other standards. We suggest, along with others, that it would be more appropriate to incorporate the requirement of this proposed standard into the appropriate section of FAC-010, FAC-014, and the TPL Planning Standards.
Response: The SDT is not certain of the conflict but the Purpose has been modified to better align with the content of the standard. The SDT recognizes that FAC-013-2 may use some of WECC's required efforts in FAC-010, FAC-014, and the TPL Planning Standards TPL-001 through TPL-004; that would not necessarily be true for entities outside of WECC. With regard to double jeopardy, the methodology in FAC-013-2 has a different date range (the Near-term Planning horizon). Therefore the standards are not completely duplicative for WECC and definitively not duplicative for non-WECC entities; even if some of the effort is the same work that is used in other standards.				
Greg Lange	Public Utility District No. 2 of Grant County	3	Negative	We still believe this standard to be redundant and unnecessary. If we are already required to have a methodology to calculate SOL's for transmission in our coordinator area, then this standard provides no additional system reliability. This is just another example of additional paper work burden with no material benefit.
Response: The SDT recognizes that FAC-013-2 may use some of WECC's required efforts in FAC-010, FAC-014, and the TPL Planning Standards TPL-001 through TPL-004; that would not necessarily be true for entities outside of WECC. With regard to redundancy, the methodology in FAC-013-2 has a different date range (the Near-term Planning horizon). Therefore the standards are not completely duplicative for WECC and definitively not duplicative for non-WECC				

Balloter	Entity	Segment	Vote	Comment
entities; even if some of the effort is the same work that is used in other standards.				
Robert Kondziolka	Salt River Project	1	Negative	SRP finds 3 problems with the proposed FAC-013-2 R4: 1. The current version states that the Transfer Capability assessment must be done "During each calendar year..." There is ambiguity in that it doesn't specifically state that simulations don't have to be run each year for every year in the Near Term Planning Horizon. It should be clear from a Compliance perspective that simulations are only required to be run if required by the entity's Transfer Capability Methodology 2. The current version states that the assessment is based on the simulations performed "...for at least one year in the Near-Term Transmission Planning Horizon." a. This means that the assessment should review a simulation associated with one year within the Near-Term Planning Horizon. As a result, a simulation must be run a minimum of once every 5 years even if there are no system changes that would impact simulation assumptions. This may not be necessary. b. The requirement states that any simulation that represents the system condition within the Near-Term Planning Horizon can be used for assessment. How is it determined which simulation is used? This does not link the chosen simulation to any reliability concern. 3. The current version does not require specific product requirements from the assessment. In other words, if the assessment was done, and adjustments to Transfer Capability were identified, the Standard does not specifically require that the adjustments be noted and provided to the entities that receive the assessment.
John T. Underhill	Salt River Project	3	Negative	
Glen Reeves	Salt River Project	5	Negative	
Response: R4. The SDT agrees with the concern that R4 requires modification and has incorporated appropriate changes into the standard. 1&2a The SDT believes that it is important to run simulations annually to ensure no changes outside the Planning Coordinator's system will impact the assessment result. 2b FAC-013-2 has been written to provide flexibility to the Planning Coordinator to perform the assessment according to their knowledge of the behavior and needs of their system. 3. The purpose of the standard is to focus more on the limiting facilities that are identified under the stress of specific energy transfers, rather than the specific values.				

Balloter	Entity	Segment	Vote	Comment
Charles H Yeung	Southwest Power Pool	2	Negative	SPP votes no because we support the ISO RTO SRC comments for this standard. We believe there are too many outstanding issues the SDT needs to address - and should be addressed prior to taking a ballot.
Response: Please see our response to the ISO RTO SRC comments for this standard.				
Travis Metcalfe	Tacoma Public Utilities	3	Negative	Tacoma Power is voting Negative. Based on our analysis of the proposed FAC-013-2 revisions and subsequent discussions today: 1) The currently balloted standard & requirements should apply to RC and/or entities with major, critical transfer paths, not a system that is primarily a load serving system. We think the existing FAC-012-1 & FAC-013-1 describe the applicability with appropriate clarity. The revision should retain the applicability provisions as they exist in the existing standards FAC-012-1 & FAC-013-1. 2) We believe all the requirements in the balloted standard are duplicative and are already covered by the requirements in TPL-001 thru TPL-004, FAC-010, & FAC-014. Therefore, this created a possibility for multiple fines on a single offense. It is a poor practice to substantially repeat requirements from other standards, difficulties with subsequent revisions in multiple standards, and concerns about double-jeopardy. 3) Lastly, the revision is written too ambiguous and subject to multiple interpretations. Thank you for your consideration.
Keith Morisette	Tacoma Public Utilities	4	Negative	
Michael C Hill	Tacoma Public Utilities	6	Negative	
Response: 1. The applicability was assigned to the PC because of their generally wider area view and to be in accord with a FERC directive. If the entity is a registered PC they must comply. 2. The SDT recognizes that FAC-013-2 may use some of WECC's required efforts in FAC-010, FAC-014, and the TPL Planning Standards TPL-001 through TPL-004; that would not necessarily be true for entities outside of WECC. With regard to double jeopardy, the methodology in FAC-013-2 has a different date range (the Near-term Planning horizon). Therefore the standards are not completely duplicative for WECC and definitively not duplicative for non-WECC entities; even if some of the effort is the same work that is used in other standards. 3. The comment lacks sufficient specificity for the SDT to render a response.				
Ronald L Donahey	Tampa Electric Co.	3	Negative	R2 is confusing. The main requirement requires distribution of the methodology; however, bullet 2.2 requires distribution of the results. Which is it? It would seem bullet 2.2 needs to be redrafted to refer to the methodology since the distribution of results is in R5.
Response: R2.2 requires the distribution of the Planning Coordinator's Transfer Capability Methodology, not the assessment results. The SDT clarified the intent by modifying Part 2.2 to require distribution of the methodology to entities that have a reliability-related need for the methodology and modified R5 to clarify that the assessment results must be shared with entities that have a reliability-related need for the information, subject to confidentiality rules.				

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Keith V. Carman	Tri-State G & T Association, Inc.	1	Negative	Tri-State's has submitted comments to support the negative vote through the electronic form provided on the Project 2010-10 Standards page.
Janelle Marriott	Tri-State G & T Association, Inc.	3	Negative	Reference Tri-State Generation and Transmission Assn., Inc. Formal comments submitted to NERC electronically via the Project 2010-10 FAC Order 729 Formal Comment link.
Response: Please refer to response to comments in Consideration of Comments on FAC-013-2.				
John Tolo	Tucson Electric Power Co.	1	Negative	There is a conflict between the purpose statement and the title of the standard, as well as a concern regarding the potential for double jeopardy given their belief that the requirements of the proposed FAC-013-2 are duplicative with other standards. It is suggested that it would be more appropriate to incorporate the requirement of this proposed standard into the appropriate section of FAC-010, FAC-014, and the TPL Planning Standards. thank you
Response: The SDT is not certain of the conflict but the Purpose has been modified to better align with the content of the standard. The SDT recognizes that FAC-013-2 may use some of WECC's required efforts in FAC-010, FAC-014, and the TPL Planning Standards TPL-001 through TPL-004; that would not necessarily be true for entities outside of WECC. With regard to double jeopardy, the methodology in FAC-013-2 has a different date range (the Near-term Planning horizon). Therefore the standards are not completely duplicative for WECC and definitively not duplicative for non-WECC entities; even if some of the effort is the same work that is used in other standards.				
Jonathan Appelbaum	United Illuminating Co.	1	Affirmative	UI would prefer the proper purpose statement to be: "To ensure that Planning Coordinators have a methodology for, and perform an annual assessment of the ability to transfer energy (in the Near-Term Transmission Planning Horizon)."
Response: The purpose of the standard is to focus more on the limiting facilities that are identified under the stress of specific energy transfers. The purpose of the statement has been modified accordingly.				
Brandy A Dunn	Western Area Power Administration	1	Negative	FAC-013-2 seems to be intended to be a Transfer Capability methodology only. The entities with a need to determine Transfer Capabilities in the Planning Horizon apply the methodology in a Planning Horizon year of their choosing. According to the December 9, 2010 White Paper for FAC-013-2, there is a desire to "add to the portfolio of knowledge for planning for future reliable operation of the BES" and "to identify potential future weaknesses in the system." We also suggest a Transfer Capability assessment belongs in the new draft TPL-001-2 where it could be studied in one of the Near-Term TPL studies, and where past Transfer Capability studies (as qualified in R2.6 of TPL-001-2 Draft 6) would be acceptable under the test for no material changes in the system (don't force an annual assessment).
Response: 1.The SDT believes the Standard is consistent with your comments and applies to the Near Term Planning Horizon. 2. The SDT does not disagree that it may be appropriate to move the requirements of FAC-013-2 into the TPL standards at some time in the future.				

Balloter	Entity	Segment	Vote	Comment
Louise McCarren	Western Electricity Coordinating Council	10	Affirmative	We agree that the requirements of proposed FAC-013-2 pose no threat to reliability and, in fact, are beneficial to reliability. However, we also believe that the requirements of proposed FAC-013-2 are duplicative of the efforts required by FAC-010, FAC-014, and the TPL Planning Standards TPL-001 through TPL-004. For clarity and ease of implementation, the requirements of proposed FAC-013-2 should be incorporated as new requirements or added into the appropriate requirements of existing standards FAC-010, FAC-014, and the TPL Planning Standards. The efforts to implement FERC's directives into the TPL-001 through TPL-004 planning standards have resulted in clarification of multiple sensitivities that must be considered when conducting the Transmission Assessments required by the new TPL-001-1 planning standard. The information gleaned by conducting and assessing these sensitivity studies would provide the Planning Coordinator with the same information regarding the impact of system changes on their Transfer Capability as obtained by meeting the requirements in the proposed FAC-013-2. Because some entities my vote in the negative for FAC-013-2 out of concerns related to double jeopardy for any potential violations of the proposed FAC-013-2 and currently existing standards, incorporating the requirements of FAC-013-2 into the appropriate existing standards may be more acceptable to the industry.
Response The SDT recognizes that FAC-013-2 may use some of WECC's required efforts in FAC-010, FAC-014, and the TPL Planning Standards TPL-001 through TPL-004; that would not necessarily be true for entities outside of WECC. Regardless, the methodology in FAC-013-2 has a different date range (the Near-term Planning horizon). Therefore the standards are not completely duplicative for WECC and definitively not duplicative for non-WECC entities; even if some of the effort is the same work that is used in other standards. FAC-013-2 has been written to provide flexibility to the Planning Coordinator to perform the assessment according to their knowledge of the behavior and needs of their system. The MOD and TPL Standards do not afford such flexibility.				
Gregory L Pieper	Xcel Energy, Inc.	1	Negative	Please refer to Xcel Energy's detailed comments submitted concurrently
Michael Ibold	Xcel Energy, Inc.	3	Negative	
Liam Noailles	Xcel Energy, Inc.	5	Negative	
David F. Lemmons	Xcel Energy, Inc.	6	Negative	
Response Please refer to response to comments in Consideration of Comments on FAC-013-2.				

A. Introduction

1. **Title:** **Transfer Capability Methodology**
2. **Number:** FAC-012-1
3. **Purpose:** To ensure that Transfer Capabilities used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.
4. **Applicability**
   - **4.1.** Reliability Coordinator required by its Regional Reliability Organization to establish inter-regional and intra-regional Transfer Capabilities
   - **4.2.** Planning Authority required by its Regional Reliability Organization to establish inter-regional and intra-regional Transfer Capabilities
5. **Effective Date:** August 7, 2006

B. Requirements

R1. The Reliability Coordinator and Planning Authority shall each document its current methodology used for developing its inter-regional and intra-regional Transfer Capabilities (Transfer Capability Methodology). The Transfer Capability Methodology shall include all of the following:

- **R1.1.** A statement that Transfer Capabilities shall respect all applicable System Operating Limits (SOLs).
- **R1.2.** A definition stating whether the methodology is applicable to the planning horizon or the operating horizon.
- **R1.3.** A description of how each of the following is addressed, including any reliability margins applied to reflect uncertainty with projected BES conditions:
  - **R1.3.1.** Transmission system topology
  - **R1.3.2.** System demand
  - **R1.3.3.** Generation dispatch
  - **R1.3.4.** Current and projected transmission uses

R2. The Reliability Coordinator shall issue its Transfer Capability Methodology, and any changes to that methodology, prior to the effectiveness of such changes, to all of the following:

- **R2.1.** Each Adjacent Reliability Coordinator and each Reliability Coordinator that indicated a reliability-related need for the methodology.
- **R2.2.** Each Planning Authority and Transmission Planner that models any portion of the Reliability Coordinator's Reliability Coordinator Area.
- **R2.3.** Each Transmission Operator that operates in the Reliability Coordinator Area.

R3. The Planning Authority shall issue its Transfer Capability Methodology, and any changes to that methodology, prior to the effectiveness of such changes, to all of the following:

- **R3.1.** Each Transmission Planner that works in the Planning Authority's Planning Authority Area.
- **R3.2.** Each Adjacent Planning Authority and each Planning Authority that indicated a reliability-related need for the methodology.

R3.3. Each Reliability Coordinator and Transmission Operator that operates any portion of the Planning Authority's Planning Authority Area.

R4. If a recipient of the Transfer Capability Methodology provides documented technical comments on the methodology, the Reliability Coordinator or Planning Authority shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the Transfer Capability Methodology and, if no change will be made to that Transfer Capability Methodology, the reason why.

C. Measures

M1. The Planning Authority and Reliability Coordinator's methodology for determining Transfer Capabilities shall each include all of the items identified in FAC-012 Requirement 1.1 through Requirement 1.3.4.

M2. The Reliability Coordinator shall have evidence it issued its Transfer Capability Methodology in accordance with FAC-012 Requirement 2 through Requirement R2.3.

M3. The Planning Authority shall have evidence it issued its Transfer Capability Methodology in accordance with FAC-012 Requirement 3 through Requirement 3.3.

M4. If the recipient of the Transfer Capability Methodology provides documented comments on its technical review of that Transfer Capability Methodology, the Reliability Coordinator or Planning Authority that distributed that Transfer Capability Methodology shall have evidence that it provided a written response to that commenter in accordance with FAC-012 Requirement 4.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Timeframe

Each Planning Authority and Reliability Coordinator shall self-certify its compliance to the Compliance Monitor at least once every three years. New Planning Authorities and Reliability Coordinators shall each demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last finding of non-compliance.

1.3. Data Retention

The Planning Authority and Reliability Coordinator shall each keep all superseded portions to its Transfer Capability Methodology for 12 months beyond the date of the change in that methodology and shall keep all documented comments on the Transfer Capability Methodology and associated responses for three years. In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant.

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Planning Authority and Reliability Coordinator shall each make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 Transfer Capability Methodology.

1.4.2 Superseded portions of its Transfer Capability Methodology that have been made within the past 12 months.

1.4.3 Documented comments provided by a recipient of the Transfer Capability Methodology on its technical review of the Transfer Capability Methodology, and the associated responses.

2. Levels of Non-Compliance

2.1. Level 1: There shall be a level one non-compliance if either of the following conditions exists:

2.1.1 The Transfer Capability Methodology is missing any one of the required statements or descriptions identified in FAC-012 R1.1 through R1.3.4.

2.1.2 No evidence of responses to a recipient’s comments on the Transfer Capability Methodology.

2.2. Level 2: The Transfer Capability Methodology is missing a combination of two of the required statements or descriptions identified in FAC-012 R1.1 through R1.3.4, or a combination thereof.

2.3. Level 3: The Transfer Capability Methodology is missing a combination of three or more of the required statements or descriptions identified in FAC-012 R1.1 through R1.3.4.

2.4. Level 4: The Transfer Capability Methodology was not issued to all of the required entities.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
1	08/01/05	1. Lower cased the word “draft” and “drafting team” where appropriate. 2. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).” 3. Changed “Timeframe” to “Time Frame” in item D, 1.2.	01/20/06

A. Introduction

1. **Title:** **Establish and Communicate Transfer Capabilities**

2. **Number:** FAC-013-1

3. **Purpose:** To ensure that Transfer Capabilities used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

4. **Applicability**

   4.1. Reliability Coordinator required by its Regional Reliability Organization to establish inter-regional and intra-regional Transfer Capabilities

   4.2. Planning Authority required by its Regional Reliability Organization to establish inter-regional and intra-regional Transfer Capabilities

5. **Effective Date:** October 7, 2006

B. Requirements

R1. The Reliability Coordinator and Planning Authority shall each establish a set of inter-regional and intra-regional Transfer Capabilities that is consistent with its current Transfer Capability Methodology.

R2. The Reliability Coordinator and Planning Authority shall each provide its inter-regional and intra-regional Transfer Capabilities to those entities that have a reliability-related need for such Transfer Capabilities and make a written request that includes a schedule for delivery of such Transfer Capabilities as follows:

R2.1. The Reliability Coordinator shall provide its Transfer Capabilities to its associated Regional Reliability Organization(s), to its adjacent Reliability Coordinators, and to the Transmission Operators, Transmission Service Providers and Planning Authorities that work in its Reliability Coordinator Area.

R2.2. The Planning Authority shall provide its Transfer Capabilities to its associated Reliability Coordinator(s) and Regional Reliability Organization(s), and to the Transmission Planners and Transmission Service Provider(s) that work in its Planning Authority Area.

C. Measures

M1. The Reliability Coordinator and Planning Authority shall each be able to demonstrate that it developed its Transfer Capabilities consistent with its Transfer Capability Methodology.

M2. The Reliability Coordinator and Planning Authority shall each have evidence that it provided its Transfer Capabilities in accordance with schedules supplied by the requestors of such Transfer Capabilities.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility
   Regional Reliability Organization

   1.2. Compliance Monitoring Period and Reset Timeframe

   The Reliability Coordinator and Planning Authority shall each verify compliance through self-certification submitted to the Compliance Monitor annually. The Compliance

Monitor may conduct a targeted audit once in each calendar year (January–December) and an investigation upon a complaint to assess compliance.

The Performance-Reset Period shall be twelve months from the last finding of non-compliance.

1.3. Data Retention

The Planning Authority and Reliability Coordinator shall each keep documentation for 12 months. In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant.

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Planning Authority and Reliability Coordinator shall each make the following available for inspection during a targeted audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 Transfer Capability Methodology.

1.4.2 Inter-regional and Intra-regional Transfer Capabilities.

1.4.3 Evidence that Transfer Capabilities were distributed.

1.4.4 Distribution schedules provided by entities that requested Transfer Capabilities.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: Not all requested Transfer Capabilities were provided in accordance with their respective schedules.

2.3. Level 3: Transfer Capabilities were not developed consistent with the Transfer Capability Methodology.

2.4. Level 4: No requested Transfer Capabilities were provided in accordance with their respective schedules.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
1	08/01/05	1. Changed incorrect use of certain hyphens (-) to “en dash (–).” 2. Lower cased the word “draft” and “drafting team” where appropriate. 3. Changed Anticipated Action #5, page 1, from “30-day” to “Thirty-day.” 4. Added or removed “periods.”	01/20/05

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Implementation Plan for Standard FAC-013-2
Assessment of Transfer Capability for the Near-term Transmission Planning Horizon

Prerequisite Approvals

There are no Standard Authorization Requests (SARs) that must be implemented before this standard can be implemented.

FAC-013-2 cannot be implemented before the following standards become effective:

- MOD-001-1 — Available Transmission System Capability
- MOD-028-1— Area Interchange Methodology
- MOD-029-1 — Rated System Path Methodology
- MOD-030-2 — Flowgate Methodology

New or Modified Definitions

The following definitions shall become effective when FAC-013-2 becomes effective:

Near-Term Transmission Planning Horizon: The transmission planning period that covers years one through five.

Year One: The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For the Planning Assessment started in a given calendar year, Year One includes the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One includes the forecasted peak Load period for either 2012 or 2013.

Modified Standards

FAC-012-1 and FAC-013-1 should be retired when FAC-013-2 becomes effective.

FAC-012-1 – Transfer Capability Methodology

FAC-013-1 – Establish and Communicate Transfer Capabilities

Compliance with Standards

Once the standard becomes effective, the responsible entity identified in the applicability section of the standard must comply with the requirements. This includes:

- Planning Coordinator

Proposed Effective Date

In those jurisdictions where regulatory approval is required, the latter of either the first day of the first calendar quarter twelve months after applicable regulatory approval or the first day of the first calendar quarter six months after MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-2 are effective.

In those jurisdictions where no regulatory approval is required, the latter of either the first day of the first calendar quarter twelve months after Board of Trustees adoption or the first day of the first calendar quarter six months after MOD-001-1, MOD-028-1, MOD-029-1 and MOD-030-2 are effective.

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Implementation Plan for Standard FAC-013-2
Assessment of Transfer Capability for the Near-term Transmission Planning Horizon

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There are no Standard Authorization Requests (SARs) that must be implemented before this standard can be implemented.

FAC-013-2 cannot be implemented before the following standards become effective:

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New or Modified Definitions

The following definitions shall become effective when FAC-013-2 becomes effective:

Near-Term Transmission Planning Horizon: The transmission planning period that covers years one through five.

Year One: The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For the Planning Assessment started in a given calendar year, Year One includes the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One includes the forecasted peak Load period for either 2012 or 2013.

Modified Standards

FAC-012-1 and FAC-013-1 should be retired when FAC-013-2 becomes effective.

FAC-012-1 – Transfer Capability Methodology
FAC-013-1 – Establish and Communicate Transfer Capabilities

Compliance with Standards

Once the standard becomes effective, the responsible entity identified in the applicability section of the standard must comply with the requirements. This includes:

- Planning Coordinator

Proposed Effective Date

In those jurisdictions where regulatory approval is required, the latter of either the first day of the first calendar quarter twelve months after applicable regulatory approval or the first day of the first calendar quarter six months after MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-2 are effective.

In those jurisdictions where no regulatory approval is required, the latter of either the first day of the first calendar quarter twelve months after Board of Trustees adoption or the first day of the first calendar quarter six months after MOD-001-1, MOD-028-1, MOD-029-1 and MOD-030-2 are effective.

Definitions of Terms Used in Standard

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

Near-Term Transmission Planning Horizon: The transmission planning period that covers Year One through five.

Year One: The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For an assessment started in a given calendar year, Year One includes the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One includes the forecasted peak Load period for either 2012 or 2013.

A. Introduction

1. **Title: Assessment of Transfer Capability for the Near-Term Transmission Planning Horizon**

2. **Number:** FAC-013-2

3. **Purpose:** To ensure that Planning Coordinators have a methodology for, and perform an annual assessment to identify potential future Transmission System weaknesses and limiting Facilities that could impact the Bulk Electric System's (BES) ability to reliably transfer energy in the Near-Term Transmission Planning Horizon..

4. **Applicability:**

   4.1. Planning Coordinators

5. **Effective Date:**

   In those jurisdictions where regulatory approval is required, the latter of either the first day of the first calendar quarter twelve months after applicable regulatory approval or the first day of the first calendar quarter six months after MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-2 are effective.

   In those jurisdictions where no regulatory approval is required, the latter of either the first day of the first calendar quarter twelve months after Board of Trustees adoption or the first day of the first calendar quarter six months after MOD-001-1, MOD-028-1, MOD-029-1 and MOD-030-2 are effective.

B. Requirements

R1. Each Planning Coordinator shall have a documented methodology it uses to perform an annual assessment of Transfer Capability in the Near-Term Transmission Planning Horizon (Transfer Capability methodology). The Transfer Capability methodology shall include, at a minimum, the following information: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. Criteria for the selection of the transfers to be assessed.

1.2. A statement that the assessment shall respect known System Operating Limits (SOLs).

1.3. A statement that the assumptions and criteria used to perform the assessment are consistent with the Planning Coordinator's planning practices.

1.4. A description of how each of the following assumptions and criteria used in performing the assessment are addressed:

1.4.1. Generation dispatch, including but not limited to long term planned outages, additions and retirements.

1.4.2. Transmission system topology, including but not limited to long term planned Transmission outages, additions, and retirements.

1.4.3. System demand.

1.4.4. Current approved and projected Transmission uses.

1.4.5. Parallel path (loop flow) adjustments.

1.4.6. Contingencies

1.4.7. Monitored Facilities.

1.5. A description of how simulations of transfers are performed through the adjustment of generation, Load or both.

R2. Each Planning Coordinator shall issue its Transfer Capability methodology, and any revisions to the Transfer Capability methodology, to the following entities subject to the following: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]

2.1. Distribute to the following prior to the effectiveness of such revisions:

2.1.1. Each Planning Coordinator adjacent to the Planning Coordinator's Planning Coordinator area or overlapping the Planning Coordinator's area.

2.1.2. Each Transmission Planner within the Planning Coordinator's Planning Coordinator area.

2.2. Distribute to each functional entity that has a reliability-related need for the Transfer Capability methodology and submits a request for that methodology within 30 calendar days of receiving that written request.

R3. If a recipient of the Transfer Capability methodology provides documented concerns with the methodology, the Planning Coordinator shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the Transfer Capability methodology and, if no change will be made to that Transfer Capability methodology, the reason why. [Violation Risk Factor: Lower][Time Horizon: Long-term Planning]

R4. During each calendar year, each Planning Coordinator shall conduct simulations and document an assessment based on those simulations in accordance with its Transfer Capability methodology for at least one year in the Near-Term Transmission Planning Horizon. [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]

R5. Each Planning Coordinator shall make the documented Transfer Capability assessment results available within 45 calendar days of the completion of the assessment to the recipients of its Transfer Capability methodology pursuant to Requirement R2, Parts 2.1 and Part 2.2. However, if a functional entity that has a reliability related need for the results of the annual assessment of the Transfer Capabilities makes a written request for such an assessment after the completion of the assessment, the Planning Coordinator shall make the documented Transfer Capability assessment results available to that entity within 45 calendar days of receipt of the request [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]

R6. If a recipient of a documented Transfer Capability assessment requests data to support the assessment results, the Planning Coordinator shall provide such data to that entity within 45 calendar days of receipt of the request. The provision of such data shall be subject to the legal and regulatory obligations of the Planning Coordinator's area regarding the disclosure of confidential and/or sensitive information. [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]

C. Measures

M1. Each Planning Coordinator shall have a Transfer Capability methodology that includes the information specified in Requirement R1.

M2. Each Planning Coordinator shall have evidence such as dated e-mail or dated transmittal letters that it provided the new or revised Transfer Capability methodology in accordance with Requirement R2

M3. Each Planning Coordinator shall have evidence, such as dated e-mail or dated transmittal letters, that the Planning Coordinator provided a written response to that commenter in accordance with Requirement R3.

M4. Each Planning Coordinator shall have evidence such as dated assessment results, that it conducted and documented a Transfer Capability assessment in accordance with Requirement R4.

M5. Each Planning Coordinator shall have evidence, such as dated copies of e-mails or transmittal letters, that it made its documented Transfer Capability assessment available to the entities in accordance with Requirement R5.

M6. Each Planning Coordinator shall have evidence, such as dated copies of e-mails or transmittal letters, that it made its documented Transfer Capability assessment data available in accordance with Requirement R6.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Data Retention

The Planning Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Planning Coordinator shall have its current Transfer Capability methodology and any prior versions of the Transfer Capability methodology that were in force since the last compliance audit to show compliance with Requirement R1.
- The Planning Coordinator shall retain evidence since its last compliance audit to show compliance with Requirement R2.
- The Planning Coordinator shall retain evidence to show compliance with Requirements R3, R4, R5 and R6 for the most recent assessment.
- If a Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time periods specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Planning Coordinator has a Transfer Capability methodology but failed to address one or two of the items listed in Requirement R1, Part 1.4.	The Planning Coordinator has a Transfer Capability methodology, but failed to incorporate one of the following Parts of Requirement R1 into that methodology: • Part 1.1 • Part 1.2 • Part 1.3 • Part 1.5 OR The Planning Coordinator has a Transfer Capability methodology but failed to address three of the items listed in Requirement R1, Part 1.4.	The Planning Coordinator has a Transfer Capability methodology, but failed to incorporate one of the following Parts of Requirement R1 into that methodology: • Part 1.1 • Part 1.2 • Part 1.3 • Part 1.5 OR The Planning Coordinator has a Transfer Capability methodology but failed to address four of the items listed in Requirement R1, Part 1.4.	The Planning Coordinator did not have a Transfer Capability methodology. OR The Planning Coordinator has a Transfer Capability methodology, but failed to incorporate one of the following Parts of Requirement R1 into that methodology: • Part 1.1 • Part 1.2 • Part 1.3 • Part 1.5 OR The Planning Coordinator has a Transfer Capability methodology but failed to address more than four of the items listed in Requirement R1, Part 1.4.

R2	The Planning Coordinator notified one or more of the parties specified in Requirement R2 of a new or revised Transfer Capability methodology after its implementation, but not more than 30 calendar days after its implementation. OR The Planning Coordinator provided the transfer Capability methodology more than 30 calendar days but not more than 60 calendar days after the receipt of a request.	The Planning Coordinator notified one or more of the parties specified in Requirement R2 of a new or revised Transfer Capability methodology more than 30 calendar days after its implementation, but not more than 60 calendar days after its implementation. OR The Planning Coordinator provided the Transfer Capability methodology more than 60 calendar days but not more than 90 calendar days after receipt of a request	The Planning Coordinator notified one or more of the parties specified in Requirement R2 of a new or revised Transfer Capability methodology more than 60 calendar days, but not more than 90 calendar days after its implementation. OR The Planning Coordinator provided the Transfer Capability methodology more than 90 calendar days but not more than 120 calendar days after receipt of a request.	The Planning Coordinator failed to notify one or more of the parties specified in Requirement R2 of a new or revised Transfer Capability methodology more than 90 calendar days after its implementation. OR The Planning Coordinator provided the Transfer Capability methodology more than 120 calendar days after receipt of a request.
R3	The Planning Coordinator provided a documented response to a documented concern with its Transfer Capability methodology as required in Requirement R3 more than 45 calendar days, but not more than 60 calendar days after receipt of the concern.	The Planning Coordinator provided a documented response to a documented concern with its Transfer Capability methodology as required in Requirement R3 more than 60 calendar days, but not more than 75 calendar days after receipt of the concern.	The Planning Coordinator provided a documented response to a documented concern with its Transfer Capability methodology as required in Requirement R3 more than 75 calendar days, but not more than 90 calendar days after receipt of the concern.	The Planning Coordinator failed to provide a documented response to a documented concern with its Transfer Capability methodology as required in Requirement R3 by more than 90 calendar days after receipt of the concern. OR The Planning Coordinator failed to respond to a documented concern with its Transfer Capability methodology.

R4.	The Planning Coordinator conducted a Transfer Capability assessment outside the calendar year, but not by more than 30 calendar days.	The Planning Coordinator conducted a Transfer Capability assessment outside the calendar year, by more than 30 calendar days, but not by more than 60 calendar days.	The Planning Coordinator conducted a Transfer Capability assessment outside the calendar year, by more than 60 calendar days, but not by more than 90 calendar days.	The Planning Coordinator failed to conduct a Transfer Capability assessment outside the calendar year by more than 90 calendar days. OR The Planning Coordinator failed to conduct a Transfer Capability assessment.

R5	The Planning Coordinator made its documented Transfer Capability assessment available to one or more of the recipients of its Transfer Capability methodology more than 45 calendar days after the requirements of R5,, but not more than 60 calendar days after completion of the assessment.	The Planning Coordinator made its Transfer Capability assessment available to one or more of the recipients of its Transfer Capability methodology more than 60 calendar days after the requirements of R5, but not more than 75 calendar days after completion of the assessment.	The Planning Coordinator made its Transfer Capability assessment available to one or more of the recipients of its Transfer Capability methodology more than 75 calendar days after the requirements of R5, but not more than 90 days after completion of the assessment.	The Planning Coordinator failed to make its documented Transfer Capability assessment available to one or more of the recipients of its Transfer Capability methodology more than 90 days after the requirements of R5. OR The Planning Coordinator failed to make its documented Transfer Capability assessment available to any of the recipients of its Transfer Capability methodology under the requirements of R5.
R6	The Planning Coordinator provided the requested data as required in Requirement R6 more than 45 calendar days after receipt of the request for data, but not more than 60 calendar days after the receipt of the request for data.	The Planning Coordinator provided the requested data as required in Requirement R6 more than 60 calendar days after receipt of the request for data, but not more than 75 calendar days after the receipt of the request for data.	The Planning Coordinator provided the requested data as required in Requirement R6 more than 75 calendar days after receipt of the request for data, but not more than 90 calendar days after the receipt of the request for data.	The Planning Coordinator provided the requested data as required in Requirement R6 more than 90 after the receipt of the request for data. OR The Planning Coordinator failed to provide the requested data as required in Requirement R6.

E. Regional Variances

None.

F. Associated Documents

Version History

Version	Date	Action	Change Tracking
1	08/01/05	1. Changed incorrect use of certain hyphens (-) to “en dash (–).” 2. Lower cased the word “draft” and “drafting team” where appropriate. 3. Changed Anticipated Action #5, page 1, from “30-day” to “Thirty-day.” 4. Added or removed “periods.”	01/20/05
2	01/23/11	Approved by BOT	

Definitions of Terms Used in Standard

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

Near-Term Transmission Planning Horizon: The ~~tranmission~~transmission planning period that covers ~~years one~~Year One through five.

Year One: The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For an assessment started in a given calendar year, Year One includes the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One includes the forecasted peak Load period for either 2012 or 2013.

A. Introduction

1. **Title:** **Assessment of Transfer Capability for the Near-Term Transmission Planning Horizon~~.~~**

2. **Number:** FAC-013-2

3. **Purpose:** To ensure that Planning Coordinators have a methodology for, and perform an annual assessment ~~of, the ability to transfer energy (in the Near-Term Transmission Planning Horizon)~~ to identify potential future Transmission System weaknesses and limiting Facilities that could impact the ~~reliability of the~~ Bulk Electric System's (BES) ability to reliably transfer energy in the Near-Term Transmission Planning Horizon..

4. **Applicability:**

   4.1. Planning Coordinators

5. **Effective Date:**

   In those jurisdictions where regulatory approval is required, the latter of either the first day of the first calendar quarter twelve months after applicable regulatory approval or the first day of the first calendar quarter six months after MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-2 are effective.

   In those jurisdictions where no regulatory approval is required, the latter of either the first day of the first calendar quarter twelve months after Board of Trustees adoption or the first day of the first calendar quarter six months after MOD-001-1, MOD-028-1, MOD-029-1 and MOD-030-2 are effective.

B. Requirements

R1. Each Planning Coordinator shall have a documented methodology it uses to perform an annual assessment of Transfer Capability in the Near-Term Transmission Planning Horizon (Transfer Capability ~~M~~methodology). The Transfer Capability ~~M~~methodology shall include, at a minimum, the following information: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. Criteria for the selection of the transfers to be assessed.

1.2. A statement that the assessment shall respect known System Operating Limits (SOLs).

1.3. A statement that the assumptions and criteria used to perform the assessment~~s~~ are consistent with the Planning Coordinator's planning practices.

1.4. A description of how each of the following assumptions and criteria used in performing the assessment are addressed:

1.4.1. Generation dispatch, including but not limited to long term planned outages, additions and retirements.

1.4.2. Transmission system topology, including but not limited to long term planned Transmission outages, additions, and retirements.

1.4.3. System demand.

1.4.4. Current approved and projected Transmission uses.

1.4.5. Parallel path (loop flow) adjustments.

1.4.6. Contingencies

1.4.7. Monitored Facilities.

1.5. A description of how simulations of transfers are performed through the adjustment of generation, Load or both.

R2. Each Planning Coordinator shall issue its Transfer Capability ~~M~~methodology, and any revisions to the Transfer Capability ~~M~~methodology, to the following entities subject to the following: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]

2.1. Distribute to the following prior to the effectiveness of such revisions:

2.1.1. Each Planning Coordinator adjacent to the Planning Coordinator's Planning Coordinator area or overlapping the Planning Coordinator's area.

2.1.2. Each Transmission Planner within the Planning Coordinator's Planning Coordinator area.

2.2. Distribute to each ~~other~~ functional entity that has a reliability-related need for the ~~results of the annual assessment of~~ Transfer ~~Capabilities~~ Capability methodology and makes a written request ~~for such assessment results~~ for that methodology within 30 calendar days of ~~such~~receiving ~~a~~ that written request.

R3. If a recipient of the Transfer Capability ~~M~~methodology provides documented concerns with the methodology, the Planning Coordinator shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the Transfer Capability ~~M~~methodology and, if no change will be made to that Transfer Capability ~~M~~methodology, the reason why. [Violation Risk Factor: Lower][Time Horizon: Long-term Planning]

R4. During each calendar year, each Planning Coordinator shall conduct simulations and document ~~a Transfer Capability~~an assessment based on ~~the~~those simulations ~~performed~~ in accordance with its Transfer Capability ~~M~~methodology for at least one year in the Near-Term Transmission Planning Horizon. [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]

R5. Each Planning Coordinator shall make the documented Transfer Capability assessment results available within 45 calendar days of the completion of the assessment to the recipients of its Transfer Capability ~~M~~methodology~~. [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]~~ pursuant to Requirement R2, Parts 2.1 and Part 2.2. However, if a functional entity that has a reliability related need for the results of the annual assessment of the Transfer Capabilities makes a written request for such an assessment after the completion of the assessment, the Planning Coordinator shall make the documented Transfer Capability assessment results available to that entity within 45 calendar days of receipt of the request [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]

R6. If a recipient of a documented Transfer Capability assessment requests data to support the assessment results, the Planning Coordinator shall provide such data to that entity within 45 calendar days of receipt of the request. The provision of such data shall be subject to the legal and regulatory obligations of the Planning Coordinator's area regarding the disclosure of confidential and/or sensitive information. [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]

C. Measures

M1. Each Planning Coordinator shall have a Transfer Capability ~~M~~methodology that includes the information specified in Requirement R1.

M2. Each Planning Coordinator shall have evidence such as dated e-mail or dated transmittal letters that it provided the new or revised Transfer Capability ~~M~~methodology in accordance with Requirement R2~~.~~

M3. Each Planning Coordinator shall have evidence, such as dated e-mail or dated transmittal letters, that the Planning Coordinator provided a written response to that commenter in accordance with Requirement R3.

M4. Each Planning Coordinator shall have evidence such as dated assessment results, that it conducted and documented a Transfer Capability assessment in accordance with Requirement R4.

M5. Each Planning Coordinator shall have evidence, such as dated copies of e-mails or transmittal letters, that it made its documented Transfer Capability assessment available to the entities in accordance with Requirement R5.

M6. Each Planning Coordinator shall have evidence, such as dated copies of e-mails or transmittal letters, that it made its documented Transfer Capability assessment data available in accordance with Requirement R6.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Data Retention

The Planning Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Planning Coordinator shall have its ~~in force~~ current Transfer Capability ~~M~~methodology and any prior versions of the Transfer Capability ~~M~~methodology that were in force since the last compliance audit to show compliance with Requirement R1.
- The Planning Coordinator shall retain evidence since its last compliance audit to show compliance with Requirement R2.
- The Planning Coordinator shall retain evidence to show compliance with Requirements R3, R4, R5 and R6 for the most recent assessment.

- If a Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time periods specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Additional Compliance Information

None~~.~~

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1~~.~~	The Planning Coordinator has a Transfer Capability ~~M~~methodology but failed to address one or two of the items listed in Requirement R1, Part 1.4.	The Planning Coordinator has a Transfer Capability ~~M~~methodology, but failed to incorporate one of the following Parts of Requirement R1 ~~Parts~~into that methodology: • Part 1.1~~,~~ • Part 1.2~~,~~ • Part 1.3 ~~and~~ • Part 1.5 OR The Planning Coordinator has a ~~Planning~~ Transfer Capability ~~M~~methodology but failed to address three of the items listed in Requirement R1, Part 1.4.	The Planning Coordinator has a Transfer Capability ~~M~~methodology, but failed to incorporate ~~two~~one of the ~~items listed in~~following Parts of Requirement R1~~, Parts~~ into that methodology: • Part 1.1~~,~~ • Part 1.2~~,~~ • Part 1.3 ~~and~~ • Part 1.5~~.~~ OR The Planning Coordinator has a ~~Planning~~ Transfer Capability ~~M~~methodology but failed to address four of the items listed in Requirement R1, Part 1.4.	The Planning Coordinator did not have a Transfer Capability ~~M~~methodology. OR The Planning Coordinator ~~had~~has a Transfer Capability ~~M~~methodology, but failed to incorporate ~~three or more~~one of the ~~items listed in~~following Parts of Requirement R1~~, Parts 1.1, 1.2, 1.3 and 1.5.~~ into that methodology: • Part 1.1 • Part 1.2 • Part 1.3 • Part 1.5 OR The Planning Coordinator has a ~~Planning~~ Transfer Capability ~~M~~methodology but failed to address more than four of the items listed in Requirement R1, Part 1.4.

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R2	The Planning Coordinator notified one or more of the parties specified in Requirement R2 of a new or revised Transfer Capability ~~M~~methodology after its implementation, but not more than 30 calendar days after its implementation. OR The Planning Coordinator provided the transfer Capability ~~M~~methodology more than 30 calendar days but not more than 60 calendar days after the receipt of a request~~ but not more than 30 calendar days after receipt of a request~~.	The Planning Coordinator notified one or more of the parties specified in Requirement R2 of a new or revised Transfer Capability ~~M~~methodology more than 30 calendar days after its implementation, but not more than 60 calendar days after its implementation. OR The Planning Coordinator provided the Transfer Capability ~~M~~methodology more than 6~~3~~0 calendar days but not more than 9~~6~~0 calendar days after receipt of a request	The Planning Coordinator notified one or more of the parties specified in Requirement R2 of a new or revised Transfer Capability ~~M~~methodology more than 60 calendar days, but not more than 90 calendar days after its implementation. OR The Planning Coordinator provided the Transfer Capability ~~M~~methodology more than ~~6~~90 calendar days but not more than ~~90~~ 120 calendar days after receipt of a request.	The Planning Coordinator failed to notify one or more of the parties specified in Requirement R2 of a new or revised Transfer Capability ~~M~~methodology more than 90 calendar days after its implementation. OR The Planning Coordinator provided the Transfer Capability ~~M~~methodology more than 12~~9~~0 calendar days after receipt of a request.
R3	The Planning Coordinator provided a documented response to a documented concern with its Transfer Capability ~~M~~methodology as required in Requirement R3 more than 45 calendar days, but not more than 60 calendar days after receipt of the concern.	The Planning Coordinator provided a documented response to a documented concern with its Transfer Capability ~~M~~methodology as required in Requirement R3 more than 60 calendar days, but not more than 75 calendar days after receipt of the concern.	The Planning Coordinator provided a documented response to a documented concern with its Transfer Capability ~~M~~methodology as required in Requirement R3 more than 75 calendar days, but not more than 90 calendar days after receipt of the concern.	The Planning Coordinator failed to provide a documented response to a documented concern with its Transfer Capability ~~M~~methodology as required in Requirement R3 by more than 90 calendar days after receipt of the concern. OR The Planning Coordinator failed to respond to a documented concern with its Transfer Capability ~~M~~methodology.

R4.	The Planning Coordinator conducted a Transfer Capability assessment outside the calendar year, but not by more than 30 calendar days.	The Planning Coordinator conducted a Transfer Capability assessment outside the calendar year, by more than 30 calendar days, but not by more than 60 calendar days.	The Planning Coordinator conducted a Transfer Capability assessment outside the calendar year, by more than 60 calendar days, but not by more than 90 calendar days.	The Planning Coordinator failed to conduct a Transfer Capability assessment outside the calendar year by more than 90 calendar days. OR The Planning Coordinator failed to conduct a Transfer Capability assessment.

R5	The Planning Coordinator made its documented Transfer Capability assessment available to one or more of the recipients of its Transfer Capability ~~M~~methodology more than 45 calendar days after the requirements of R5,~~completion of the assessment but~~, but not more than 60 calendar days after completion of the assessment.	The Planning Coordinator made its Transfer Capability assessment available to one or more of the recipients of its Transfer Capability ~~M~~methodology more than 60 calendar days after the requirements of R5~~completion of the assessment~~, but not more than 75 calendar days after completion of the assessment.	The Planning Coordinator made its Transfer Capability assessment available to one or more of the recipients of its Transfer Capability ~~M~~methodology more than 75 calendar days after the requirements of R5~~completion of the assessment~~, but not more than 90 days after completion of the assessment.	The Planning Coordinator failed to make its documented Transfer Capability assessment available to one or more of the recipients of its Transfer Capability ~~M~~methodology more than 90 days after the requirements of R5~~completion of the assessment~~. OR The Planning Coordinator failed to make its documented Transfer Capability assessment available to any of the recipients of its Transfer Capability ~~M~~methodology under the requirements of R5.
R6	The Planning Coordinator provided the requested data as required in Requirement R6 more than 45 calendar days after receipt of the request for data, but not more than 60 calendar days after the receipt of the request for data.	The Planning Coordinator provided the requested data as required in Requirement R6 more than 60 calendar days after receipt of the request for data, but not more than 75 calendar days after the receipt of the request for data.	The Planning Coordinator provided the requested data as required in Requirement R6 more than 75 calendar days after receipt of the request for data, but not more than 90 calendar days after the receipt of the request for data.	The Planning Coordinator provided the requested data as required in Requirement R6 more than 90 after the receipt of the request for data. OR The Planning Coordinator failed to provide the requested data as required in Requirement R6.

E. **Regional ~~Differences~~Variances**

None ~~identified~~.

F. Associated Documents

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Version History

Version	Date	Action	Change Tracking
1	08/01/05	1. Changed incorrect use of certain hyphens (-) to "en dash (–)." 2. Lower cased the word "draft" and "drafting team" where appropriate. 3. Changed Anticipated Action #5, page 1, from "30-day" to "Thirty-day." 4. Added or removed "periods."	01/20/05
2	~~TBD~~01/24/11	~~Modified to be consistent with directives contained in FERC Order 729~~Approved by BOT	~~TBD~~

Standards Announcement

Recirculation Ballot Window Open
Project 2010-10 – Facility Ratings Order 729
January 14-23, 2011

Now available at: https://standards.nerc.net/CurrentBallots.aspx

Project 2010-10 – Facility Ratings Order 729

A recirculation ballot window for standard FAC-013-2 — Assessment of Transfer Capability for the Near-Term Transmission Planning Horizon is open **until 8 p.m. Eastern on Sunday, January 23, 2011**.

Instructions

Members of the ballot pool associated with this project may log in and submit their votes from the following page: https://standards.nerc.net/CurrentBallots.aspx

In the recirculation ballot, votes are counted by exception. Only members of the ballot pool may cast a ballot; all ballot pool members may change their prior votes. A ballot pool member who failed to cast a ballot during the last ballot window may cast a ballot in the recirculation ballot window. If a ballot pool member does not participate in the recirculation ballot, that member's last vote cast in the successive ballot that ended on January 8, 2011 will be carried over and used to determine if there are sufficient affirmative votes for this standard to pass.

This is an extremely important ballot, as NERC is responding to a FERC directive that requires submitting modifications to FAC-012 and FAC-013 by January 28, 2011 to support the implementation of the ATC standards that were approved in 2009 and 2010. We encourage all members of the ballot pool to review the following information and the revised standard before casting a ballot.

There were several comments submitted during the last comment/ballot period that proposed clarifying changes to the standard resulting in the drafting team making the following changes.

- The proposed definition of Year One was moved from project 2006-02 – Assess Transmission and Future Needs to this project as the term "Year One" is used in the proposed definition of "Near-Term Transmission Planning Horizon."
- The Purpose statement was revised to better align with the intent of the requirements.
- The qualifying phrase, 'long-term' was added to clarify the intent of the scope of planned outages that must be addressed in the Planning Transfer methodology.
- Requirement R2, Part 2.2 was confusing as it linked responses to requests for assessment results with requests for the methodology. The team revised Part 2.2 to focus solely on distribution of the methodology, and revised Requirement R5 to address requests for assessment results, subject to

confidentiality rules.

- The VSLs for R1 were clarified, and an error in the VSLs for R2 was corrected.
- The team removed capitalization from the word, “methodology” as this is not a defined term.

The Standard Processes Manual allows drafting teams to make changes following an initial or successive ballot with a goal of improving the quality of a standard, provided those changes do not alter the applicability or scope of the proposed standard. The above changes fall into this category, as none of them change the scope, or applicability of the set of requirements. A redline version of the standard showing the modifications has been posted for stakeholder review.

Next Steps

Voting results will be posted and announced after the ballot window closes. This standard is scheduled to be submitted to the Board of Trustees on January 24, 2011, and filed for regulatory approval by January 28, 2011.

Project Background

The proposed standard addresses FERC directives from FERC Order 729 as well as stakeholder comments received during an initial formal comment period and ballot. In Order 729, FERC ruled that the ATC standards developed in Project 2006-07 did not completely address the topics covered in FAC-012 and -013 and did not fully address the associated directives from Order 693. Accordingly, FERC denied the portions of the implementation plan that would have retired these standards, and instead directed NERC to use the standards development process to make changes to the FAC standards and file those changes with FERC no later than 60 days prior to the effective date of the standards, which is April 1, 2011 (requiring the proposed changes to be filed on or before January 28, 2011).

Further details are available on the project page:
http://www.nerc.com/filez/standards/Project2010-10_FAC_Order_729.html

Standards Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Monica Benson,
Standards Process Administrator, at monica.benson@nerc.net or at 609.452.8060.

North American Electric Reliability Corporation
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-Current Ballots
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-Registered Ballot Body
-Proxy Voters

Home Page

Ballot Results	
Ballot Name:	Project 2010-10: FAC Order 729_rc
Ballot Period:	1/14/2011 - 1/23/2011
Ballot Type:	recirculation
Total # Votes:	279
Total Ballot Pool:	322
Quorum:	**86.65 % The Quorum has been reached**
Weighted Segment Vote:	68.98 %
Ballot Results:	**The Standard has Passed**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	94	1	43	0.672	21	0.328	20	10
2 - Segment 2.	11	0.9	3	0.3	6	0.6	1	1
3 - Segment 3.	76	1	37	0.661	19	0.339	10	10
4 - Segment 4.	19	1	13	0.867	2	0.133	3	1
5 - Segment 5.	60	1	25	0.694	11	0.306	12	12
6 - Segment 6.	42	1	13	0.542	11	0.458	11	7
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	6	0.4	3	0.3	1	0.1	2	0
9 - Segment 9.	5	0.3	3	0.3	0	0	1	1
10 - Segment 10.	9	0.7	7	0.7	0	0	1	1
Totals	**322**	**7.3**	**147**	**5.036**	**71**	**2.264**	**61**	**43**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Allegheny Power	Rodney Phillips	Affirmative	
1	Ameren Services	Kirit S. Shah	Negative	View
1	American Electric Power	Paul B. Johnson	Affirmative	
1	American Transmission Company, LLC	Andrew Z Pusztai	Negative	View
1	Arizona Public Service Co.	Robert D Smith	Negative	View
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Avista Corp.	Scott Kinney	Negative	View
1	BC Transmission Corporation	Gordon Rawlings	Negative	View

1	Beaches Energy Services	Joseph S. Stonecipher	Affirmative	View
1	Black Hills Corp	Eric Egge	Negative	View
1	Bonneville Power Administration	Donald S. Watkins	Negative	View
1	CenterPoint Energy	Paul Rocha	Abstain	
1	Central Maine Power Company	Brian Conroy		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Vero Beach	Randall McCamish	Affirmative	
1	Clark Public Utilities	Jack Stamper	Abstain	
1	Colorado Springs Utilities	Paul Morland	Negative	View
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	View
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	John K Loftis	Abstain	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	E.ON U.S.	Larry Monday		
1	East Kentucky Power Coop.	George S. Carruba	Affirmative	
1	Edison Electric Institute	David Batz	Abstain	
1	Empire District Electric Co.	Ralph Frederick Meyer	Affirmative	
1	Entergy Corporation	George R. Bartlett	Affirmative	
1	FirstEnergy Energy Delivery	Robert Martinko	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Abstain	
1	Gainesville Regional Utilities	Luther E. Fair	Affirmative	
1	GDS Associates, Inc.	Claudiu Cadar	Abstain	
1	Georgia Transmission Corporation	Harold Taylor, II	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Robert Solomon	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Affirmative	View
1	JEA	Ted E Hobson	Affirmative	
1	Kansas City Power & Light Co.	Michael Gammon	Affirmative	
1	Keys Energy Services	Stan T. Rzad	Negative	View
1	Lake Worth Utilities	Walt Gill	Abstain	
1	Lakeland Electric	Larry E Watt	Negative	View
1	Lee County Electric Cooperative	John W Delucca	Abstain	
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley	Abstain	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	View
1	National Grid	Saurabh Saksena		
1	Nebraska Public Power District	Richard L. Koch	Abstain	
1	Nevada Power Co.	James McMorran		
1	New York Power Authority	Arnold J. Schuff	Affirmative	
1	Northeast Utilities	David H. Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Kevin M Largura	Negative	
1	NorthWestern Energy	John Canavan	Abstain	
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Affirmative	
1	Omaha Public Power District	Douglas G Peterchuck	Abstain	
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Daryl Hanson	Abstain	
1	Pacific Gas and Electric Company	Chifong L. Thomas		
1	PacifiCorp	Colt Norrish	Affirmative	
1	PECO Energy	Ronald Schloendorn	Affirmative	
1	Platte River Power Authority	John C. Collins	Negative	View
1	Portland General Electric Co.	Frank F. Afranji	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PowerSouth Energy Cooperative	Larry D. Avery	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Abstain	
1	Progress Energy Carolinas	Sammy Roberts	Negative	View
1	Public Service Company of New Mexico	Laurie Williams	Abstain	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Chelan County	Chad Bowman	Abstain	
1	Puget Sound Energy, Inc.	Catherine Koch		
1	Rochester Gas and Electric Corp.	John C. Allen	Abstain	

1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Negative	View
1	San Diego Gas & Electric	Linda Brown		
1	Santee Cooper	Terry L. Blackwell	Abstain	
1	SCE&G	Henry Delk, Jr.	Affirmative	
1	Seattle City Light	Pawel Krupa	Abstain	
1	South Texas Electric Cooperative	Richard McLeon	Affirmative	
1	Southern California Edison Co.	Dana Cabbell	Affirmative	
1	Southern Company Services, Inc.	Horace Stephen Williamson	Affirmative	
1	Southern Illinois Power Coop.	William G. Hutchison	Negative	
1	Southwest Transmission Cooperative, Inc.	James L. Jones	Affirmative	
1	Southwestern Power Administration	Gary W Cox	Abstain	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Affirmative	
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Larry Akens	Affirmative	View
1	Tri-State G & T Association, Inc.	Keith V Carman	Negative	View
1	Tucson Electric Power Co.	John Tolo	Negative	View
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Negative	View
1	Xcel Energy, Inc.	Gregory L Pieper	Negative	View
2	Alberta Electric System Operator	Mark B Thompson	Abstain	
2	BC Hydro	Venkataramakrishnan Vinnakota	Negative	View
2	California ISO	Gregory Van Pelt	Negative	View
2	Electric Reliability Council of Texas, Inc.	Chuck B Manning		
2	Independent Electricity System Operator	Kim Warren	Affirmative	View
2	ISO New England, Inc.	Kathleen Goodman	Negative	View
2	Midwest ISO, Inc.	Jason L Marshall	Negative	View
2	New Brunswick System Operator	Alden Briggs	Affirmative	
2	New York Independent System Operator	Gregory Campoli	Negative	View
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
2	Southwest Power Pool	Charles H Yeung	Negative	View
3	Alabama Power Company	Richard J. Mandes	Affirmative	
3	Allegheny Power	Bob Reeping	Affirmative	
3	Ameren Services	Mark Peters	Negative	
3	American Electric Power	Raj Rana		
3	APS	Steven Norris	Negative	View
3	Atlantic City Electric Company	James V. Petrella	Affirmative	
3	Avista Corp.	Robert Lafferty	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington	Negative	View
3	Blue Ridge Power Agency	Duane S Dahlquist		
3	Bonneville Power Administration	Rebecca Berdahl	Negative	View
3	City of Bartow, Florida	Matt Culverhouse		
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R. Jacobson	Abstain	
3	City of Green Cove Springs	Gregg R Griffin	Negative	View
3	City of Leesburg	Phil Janik	Affirmative	
3	Cleco Corporation	Michelle A Corley	Abstain	
3	ComEd	Bruce Krawczyk	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	View
3	Consumers Energy	David A. Lapinski	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Edwin Les Barrow		
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources Services	Michael F Gildea	Abstain	
3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	View
3	East Kentucky Power Coop.	Sally Witt	Affirmative	
3	Entergy	Joel T Plessinger	Affirmative	
3	FirstEnergy Solutions	Kevin Querry	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney		
3	Florida Power & Light Co.	W. R. Schoneck	Affirmative	
3	Florida Power Corporation	Lee Schuster	Negative	View
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia Power Company	Anthony L Wilson	Affirmative	
3	Georgia System Operations Corporation	R Scott S. Barfield-McGinnis	Affirmative	

3	Great River Energy	Sam Kokkinen	Affirmative	
3	Gulf Power Company	Gwen S Frazier		
3	Hydro One Networks, Inc.	David L Kiguel	Affirmative	
3	JEA	Garry Baker	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke	Affirmative	
3	Kissimmee Utility Authority	Gregory David Woessner	Affirmative	
3	Lakeland Electric	Mace Hunter	Negative	View
3	Lincoln Electric System	Bruce Merrill	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	View
3	Manitoba Hydro	Greg C. Parent	Negative	View
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	View
3	Mississippi Power	Don Horsley	Affirmative	
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Affirmative	
3	Muscatine Power & Water	John S Bos	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	Marilyn Brown	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone		
3	Northern Indiana Public Service Co.	William SeDoris	Negative	
3	Ocala Electric Utility	David T. Anderson	Affirmative	
3	Orlando Utilities Commission	Ballard Keith Mutters	Affirmative	
3	PacifiCorp	John Apperson	Affirmative	
3	PECO Energy an Exelon Co.	Vincent J. Catania		
3	Platte River Power Authority	Terry L Baker	Negative	View
3	PNM Resources	Michael Mertz	Abstain	
3	Potomac Electric Power Co.	Robert Reuter	Affirmative	
3	Progress Energy Carolinas	Sam Waters	Negative	View
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Public Utility District No. 2 of Grant County	Greg Lange	Negative	View
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Negative	View
3	San Diego Gas & Electric	Scott Peterson		
3	Santee Cooper	Zack Dusenbury	Abstain	
3	Seattle City Light	Dana Wheelock	Abstain	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C. Young		
3	Southern California Edison Co.	David Schiada	Affirmative	
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	View
3	Tampa Electric Co.	Ronald L Donahey	Negative	View
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Negative	View
3	Wisconsin Electric Power Marketing	James R. Keller	Abstain	
3	Xcel Energy, Inc.	Michael Ibold	Negative	View
4	American Municipal Power - Ohio	Kevin Koloini	Abstain	
4	City of Clewiston	Kevin McCarthy	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Timothy Beyrle	Negative	
4	Consumers Energy	David Frank Ronk	Affirmative	
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Fort Pierce Utilities Authority	Thomas W. Richards	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Negative	View
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Abstain	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Abstain	
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Amerenue	Sam Dwyer	Negative	
5	APS	Mel Jensen	Negative	View
5	Avista Corp.	Edward F. Groce	Abstain	

5	BC Hydro and Power Authority	Clement Ma	Negative	View
5	Bonneville Power Administration	Francis J. Halpin	Negative	View
5	Chelan County Public Utility District #1	John Yale		
5	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Max Emrick	Affirmative	View
5	Cleco Power	Stephanie Huffman		
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Negative	View
5	Consumers Energy	James B Lewis	Affirmative	
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	CPS Energy	Robert B Stevens		
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	Duke Energy	Dale Q Goodwine		
5	East Kentucky Power Coop.	Stephen Ricker	Affirmative	
5	Energy Northwest - Columbia Generating Station	Doug Ramey	Affirmative	
5	Entergy Corporation	Stanley M Jaskot	Affirmative	
5	Exelon Nuclear	Michael Korchynsky	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Cynthia E Sulzer	Affirmative	
5	Kansas City Power & Light Co.	Scott Heidtbrink	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	Thomas J Trickey		
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Louisville Gas and Electric Co.	Charlie Martin		
5	Manitoba Hydro	S N Fernando	Affirmative	View
5	MEAG Power	Steven Grego	Affirmative	
5	MidAmerican Energy Co.	Christopher Schneider	Negative	View
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Gerald Mannarino		
5	Northern Indiana Public Service Co.	Michael K Wilkerson		
5	Omaha Public Power District	Mahmood Z. Safi	Abstain	
5	Orlando Utilities Commission	Richard Kinas	Affirmative	
5	Pacific Gas and Electric Company	Richard J. Padilla		
5	PacifiCorp	Sandra L. Shaffer	Affirmative	
5	Portland General Electric Co.	Gary L Tingley	Affirmative	
5	PowerSouth Energy Cooperative	Tim Hattaway	Abstain	
5	PPL Generation LLC	Annette M Bannon	Abstain	
5	Progress Energy Carolinas	Wayne Lewis	Negative	View
5	PSEG Power LLC	Jerzy A Slusarz	Affirmative	
5	RRI Energy	Thomas J. Bradish		
5	Sacramento Municipal Utility District	Bethany Hunter	Affirmative	
5	Salt River Project	Glen Reeves	Negative	View
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Abstain	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	South Carolina Electric & Gas Co.	Richard Jones	Affirmative	
5	South Mississippi Electric Power Association	Jerry W Johnson		
5	Tampa Electric Co.	RJames Rocha	Negative	
5	Tenaska, Inc.	Scott M. Helyer	Affirmative	
5	Tennessee Valley Authority	George T. Ballew	Affirmative	View
5	Tri-State G & T Association, Inc.	Barry Ingold	Negative	
5	U.S. Army Corps of Engineers Northwestern Division	Karl Bryan		
5	U.S. Bureau of Reclamation	Martin Bauer P.E.	Abstain	
5	Wisconsin Electric Power Co.	Linda Horn	Abstain	
5	Wisconsin Public Service Corp.	Leonard Rentmeester	Abstain	
5	Xcel Energy, Inc.	Liam Noailles	Negative	View
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Negative	View
6	Arizona Public Service Co.	Justin Thompson	Negative	View
6	Bonneville Power Administration	Brenda S. Anderson	Negative	
6	Cleco Power LLC	Robert Hirchak	Abstain	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Negative	View
6	Constellation Energy Commodities Group	Brenda Powell	Abstain	
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy Carolina	Walter Yeager	Affirmative	

6	Entergy Services, Inc.	Terri F Benoit		
6	Exelon Power Team	Pulin Shah	Affirmative	
6	FirstEnergy Solutions	Mark S Travaglianti	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas E Washburn	Negative	View
6	Florida Power & Light Co.	Silvia P. Mitchell	Abstain	
6	Great River Energy	Donna Stephenson		
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Negative	View
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Louisville Gas and Electric Co.	Daryn Barker		
6	Manitoba Hydro	Daniel Prowse	Affirmative	View
6	MidAmerican Energy Co.	Dennis Kimm	Negative	View
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	
6	NRG Energy, Inc.	Alan R. Johnson	Abstain	
6	Omaha Public Power District	David Ried	Abstain	
6	PacifiCorp	Scott L Smith	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Negative	View
6	Portland General Electric Co.	John Jamieson	Affirmative	
6	PPL EnergyPlus LLC	Mark A Heimbach	Abstain	
6	Progress Energy	John T Sturgeon	Negative	
6	PSEG Energy Resources & Trade LLC	James D. Hebson	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	RRI Energy	Trent Carlson		
6	Salt River Project	Mike Hummel		
6	Santee Cooper	Suzanne Ritter	Abstain	
6	Seattle City Light	Dennis Sismaet	Abstain	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Joann Wehle		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	View
6	Western Area Power Administration - UGP Marketing	John Stonebarger		
6	Xcel Energy, Inc.	David F. Lemmons	Negative	View
8		James A Maenner	Abstain	
8		Roger C Zaklukiewicz	Affirmative	
8		Edward C Stein	Affirmative	
8	JDRJC Associates	Jim D. Cyrulewski	Negative	
8	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	California Energy Commission	William Mitchell Chamberlain	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Affirmative	
9	North Carolina Utilities Commission	Kimberly J. Jones		
9	Oregon Public Utility Commission	Jerome Murray	Abstain	
9	Utah Public Service Commission	Ric Campbell	Affirmative	
10	Florida Reliability Coordinating Council	Linda Campbell	Affirmative	
10	Midwest Reliability Organization	James D Burley	Affirmative	View
10	New York State Reliability Council	Alan Adamson		
10	Northeast Power Coordinating Council, Inc.	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Carter B Edge	Affirmative	
10	Southwest Power Pool Regional Entity	Stacy Dochoda	Affirmative	
10	Texas Reliability Entity	Larry D Grimm	Abstain	
10	Western Electricity Coordinating Council	Louise McCarren	Affirmative	View

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Final Ballot Results
Project 2010-10 – Facility Ratings Order 729

Now available at: https://standards.nerc.net/Ballots.aspx

Project 2010-10 – Facility Ratings Order 729

The recirculation ballot for Project 2010-10 ended on January 23, 2011. The ballot pool approved the following:

- Approval of FAC-013-2 — Assessment of Transfer Capability for the Near-Term Transmission Planning Horizon and its associated implementation plan which includes retirement of FAC-012-1 — Transfer Capability Methodology and FAC-013-1— Establish Communicate Transfer Capabilities
- Approval of definitions for Near-term Planning Horizon and Year One

Voting statistics are listed below, and the Ballot Results Web page provides a link to the detailed results:

- Quorum: 86.65%
- Approval: 68.98%

Next Steps

This standard, its implementation plan, and new definitions were adopted and the associated VRFs and VSLs were approved by the Board of Trustees on January 24, 2011. The standard and its VRFs and VSLs, the implementation plan, and the proposed definitions will all be filed for regulatory approval by January 28, 2011.

Project Background

The proposed standard addresses FERC directives from FERC Order 729 as well as stakeholder comments received during an initial formal comment period and ballot. In Order 729, FERC ruled that the ATC standards developed in Project 2006-07 did not completely address the topics covered in FAC-012 and -013, and did not fully address the associated directives from Order 693. Accordingly, FERC denied the portions of the implementation plan that would have retired these standards, and instead directed NERC to use the standards development process to make changes to the FAC standards and file those changes with FERC no later than 60 days prior to the effective date of the standards, which is April 1, 2011 (requiring the proposed changes to be filed on or before January 28, 2011).

Further details are available on the project page:
http://www.nerc.com/filez/standards/Project2010-10_FAC_Order_729.html

Ballot Criteria

Approval requires both a (1) quorum, which is established by at least 75% of the members of the ballot pool submitting either an affirmative vote, a negative vote, or an abstention, and (2) 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.

Standards Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Monica Benson,
Standards Process Administrator, at monica.benson@nerc.net or at 609.452.8060.

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