North American Electric Reliability Council
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ATC/TTC/AFC — CBM/TRM Meeting

June 8, 2006 — noon–5 p.m.
June 9, 2006 — 8 a.m.–noon
Sheraton St. Louis City Center Hotel & Suites
40 South 14th Street
St. Louis, MO 63103
☎ (314) 231 5007

Agenda

1. Administration

a. Welcome and Introductions — Bill Blevins
b. NERC ATC/TTC/AFC– CBM/TRM Roster
c. Antitrust Compliance Guidelines — Bill Blevins
d. Review of Agenda — Bill Blevins

2. FAC Standards discussions

a. Discussion of FAC-008 **Facility Ratings Methodology**
b. Discussion of FAC-009 **Establish and Communicate Facility Ratings**
c. Discussion of FAC-010 **System Operating Limits Methodology**
d. Discussion of FAC-011 **Establish and Communicate System Operating Limits**
e. Discussion of FAC-012 **Transfer Capability Methodology**
f. Discussion of FAC-013 **Establish and Communicate Transfer Capabilities**

3. White Paper discussion

a. Network Response Methodology Differences
b. Rated Path System Methodology Differences

4. FERC NOPR PROPOSED MODIFICATIONS OF THE OATT

a. Consistency and Transparency of ATC Calculation
b. Transmission Planning — Coordinated, Open and Transparent Planning

5. Standard Document Review

a. MOD-001-1 — Bill Blevins approve for posting

b. MOD-004 through MOD-009 develop work plan — Bill Blevins

6. Future Meetings — Bill Blevins

a. Dates — future meeting dates will be determined to meet the goals and objectives
b. Locations

7. Adjourn

ATC-TTC-AFC-CBM-TRM Standards Drafting Team

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NERC ANTITRUST COMPLIANCE GUIDELINES

I. GENERAL

It is NERC's policy and practice to obey the antitrust laws and to avoid all conduct that unreasonably restrains competition. This policy requires the avoidance of any conduct that violates, or that might appear to violate, the antitrust laws. Among other things, the antitrust laws forbid any agreement between or among competitors regarding prices, availability of service, product design, terms of sale, division of markets, allocation of customers or any other activity that unreasonably restrains competition.

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

Antitrust laws are complex and subject to court interpretation that can vary over time and from one court to another. The purpose of these guidelines is to alert NERC participants and employees to potential antitrust problems and to set forth policies to be followed with respect to activities that may involve antitrust considerations. In some instances, the NERC policy contained in these guidelines is stricter than the applicable antitrust laws. Any NERC participant or employee who is uncertain about the legal ramifications of a particular course of conduct or who has doubts or concerns about whether NERC's antitrust compliance policy is implicated in any situation should consult NERC's General Counsel immediately.

II. PROHIBITED ACTIVITIES

Participants in NERC activities (including those of its committees and subgroups) should refrain from the following when acting in their capacity as participants in NERC activities (e.g., at NERC meetings, conference calls and in informal discussions):

- Discussions involving pricing information, especially margin (profit) and internal cost information and participants' expectations as to their future prices or internal costs.
- Discussions of a participant's marketing strategies.
- Discussions regarding how customers and geographical areas are to be divided among competitors.
- Discussions concerning the exclusion of competitors from markets.
- Discussions concerning boycotting or group refusals to deal with competitors, vendors or suppliers.

III. ACTIVITIES THAT ARE PERMITTED

From time to time decisions or actions of NERC (including those of its committees and subgroups) may have a negative impact on particular entities and thus in that sense adversely impact competition. Decisions and actions by NERC (including its committees and subgroups) should only be undertaken for the purpose of promoting and maintaining the reliability and adequacy of the bulk power system. If you do not have a legitimate purpose consistent with this objective for discussing a matter, please refrain from discussing the matter during NERC meetings and in other NERC-related communications.

You should also ensure that NERC procedures, including those set forth in NERC's Certificate of Incorporation and Bylaws are followed in conducting NERC business. Other NERC procedures that may be applicable to a particular NERC activity include the following:

- Reliability Standards Process Manual
- Organization and Procedures Manual for the NERC Standing Committees
- System Operator Certification Program

In addition, all discussions in NERC meetings and other NERC-related communications should be within the scope of the mandate for or assignment to the particular NERC committee or subgroup, as well as within the scope of the published agenda for the meeting.

No decisions should be made nor any actions taken in NERC activities for the purpose of giving an industry participant or group of participants a competitive advantage over other participants. In particular, decisions with respect to setting, revising, or assessing compliance with NERC reliability standards should not be influenced by anti-competitive motivations.

Subject to the foregoing restrictions, participants in NERC activities may discuss:

- Reliability matters relating to the bulk power system, including operation and planning matters such as establishing or revising reliability standards, special operating procedures, operating transfer capabilities, and plans for new facilities.

- Matters relating to the impact of reliability standards for the bulk power system on electricity markets, and the impact of electricity market operations on the reliability of the bulk power system.

- Proposed filings or other communications with state or federal regulatory authorities or other governmental entities.

- Matters relating to the internal governance, management and operation of NERC, such as nominations for vacant committee positions, budgeting and assessments, and employment matters; and procedural matters such as planning and scheduling meetings.

Any other matters that do not clearly fall within these guidelines should be reviewed with NERC's General Counsel before being discussed.

A. Introduction

1. **Title:** **Facility Ratings Methodology**

2. **Number:** FAC-008-1

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

4. **Applicability**

   4.1. Transmission Owner

   4.2. Generator Owner

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

B. Requirements

R1. The Transmission Owner and Generator Owner shall each document its current methodology used for developing Facility Ratings (Facility Ratings Methodology) of its solely and jointly owned Facilities. The methodology shall include all of the following:

R1.1. A statement that a Facility Rating shall equal the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility.

R1.2. The method by which the Rating (of major BES equipment that comprises a Facility) is determined.

R1.2.1. The scope of equipment addressed shall include, but not be limited to, generators, transmission conductors, transformers, relay protective devices, terminal equipment, and series and shunt compensation devices.

R1.2.2. The scope of Ratings addressed shall include, as a minimum, both Normal and Emergency Ratings.

R1.3. Consideration of the following:

R1.3.1. Ratings provided by equipment manufacturers.

R1.3.2. Design criteria (e.g., including applicable references to industry Rating practices such as manufacturer’s warranty, IEEE, ANSI or other standards).

R1.3.3. Ambient conditions.

R1.3.4. Operating limitations.

R1.3.5. Other assumptions.

R2. The Transmission Owner and Generator Owner shall each make its Facility Ratings Methodology available for inspection and technical review by those Reliability Coordinators, Transmission Operators, Transmission Planners, and Planning Authorities that have responsibility for the area in which the associated Facilities are located, within 15 business days of receipt of a request.

R3. If a Reliability Coordinator, Transmission Operator, Transmission Planner, or Planning Authority provides written comments on its technical review of a Transmission Owner’s or Generator Owner’s Facility Ratings Methodology, the Transmission Owner or Generator Owner shall provide a written response to that commenting entity within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the

Facility Ratings Methodology and, if no change will be made to that Facility Ratings Methodology, the reason why.

C. Measures

M1. The Transmission Owner and Generator Owner shall each have a documented Facility Ratings Methodology that includes all of the items identified in FAC-008 Requirement 1.1 through FAC-008 Requirement 1.3.5.

M2. The Transmission Owner and Generator Owner shall each have evidence it made its Facility Ratings Methodology available for inspection within 15 business days of a request as follows:

M2.1 The Reliability Coordinator shall have access to the Facility Ratings Methodologies used for Rating Facilities in its Reliability Coordinator Area.

M2.2 The Transmission Operator shall have access to the Facility Ratings Methodologies used for Rating Facilities in its portion of the Reliability Coordinator Area.

M2.3 The Transmission Planner shall have access to the Facility Ratings Methodologies used for Rating Facilities in its Transmission Planning Area.

M2.4 The Planning Authority shall have access to the Facility Ratings Methodologies used for Rating Facilities in its Planning Authority Area.

M3. If the Reliability Coordinator, Transmission Operator, Transmission Planner, or Planning Authority provides documented comments on its technical review of a Transmission Owner's or Generator Owner's Facility Ratings Methodology, the Transmission Owner or Generator Owner shall have evidence that it provided a written response to that commenting entity within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the Facility Ratings Methodology and, if no change will be made to that Facility Ratings Methodology, the reason why.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

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

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

The Transmission Owner and Generator Owner shall each keep all superseded portions of its Facility Ratings Methodology for 12 months beyond the date of the change in that methodology and shall keep all documented comments on the Facility Ratings Methodology and associated responses for three years. In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant.

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

1.4. Additional Compliance Information

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

1.4.1 Facility Ratings Methodology

1.4.2 Superseded portions of its Facility Ratings Methodology that had been replaced, changed or revised within the past 12 months

1.4.3 Documented comments provided by a Reliability Coordinator, Transmission Operator, Transmission Planner or Planning Authority on its technical review of a Transmission Owner's or Generator Owner's Facility Ratings methodology, and the associated responses

2. Levels of Non-Compliance

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

2.1.1 The Facility Ratings Methodology does not contain a statement that a Facility Rating shall equal the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility.

2.1.2 The Facility Ratings Methodology does not address one of the required equipment types identified in FAC-008 R1.2.1.

2.1.3 No evidence of responses to a Reliability Coordinator's, Transmission Operator, Transmission Planner, or Planning Authority's comments on the Facility Ratings Methodology.

2.2. Level 2: The Facility Ratings Methodology is missing the assumptions used to determine Facility Ratings or does not address two of the required equipment types identified in FAC-008 R1.2.1.

2.3. Level 3: The Facility Ratings Methodology does not address three of the required equipment types identified in FAC-008-1 R1.2.1.

2.4. Level 4: The Facility Ratings Methodology does not address both Normal and Emergency Ratings or the Facility Ratings Methodology was not made available for inspection within 15 business days of receipt of a request.

E. Regional Differences

None Identified.

Version History

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

		Frame" and "twelve" to "12" in item D, 1.2.	

A. Introduction

1. **Title:** **Establish and Communicate Facility Ratings**

2. **Number:** FAC-009-1

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

4. **Applicability**

   4.1. Transmission Owner

   4.2. Generator Owner

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

B. Requirements

R1. The Transmission Owner and Generator Owner shall each establish Facility Ratings for its solely and jointly owned Facilities that are consistent with the associated Facility Ratings Methodology.

R2. The Transmission Owner and Generator Owner shall each provide Facility Ratings for its solely and jointly owned Facilities that are existing Facilities, new Facilities, modifications to existing Facilities and re-ratings of existing Facilities to its associated Reliability Coordinator(s), Planning Authority(ies), Transmission Planner(s), and Transmission Operator(s) as scheduled by such requesting entities.

C. Measures

M1. The Transmission Owner and Generator Owner shall each be able to demonstrate that it developed its Facility Ratings consistent with its Facility Ratings Methodology.

M1.1 The Transmission Owner's and Generator Owner's Facility Ratings shall each include ratings for its solely and jointly owned Facilities including new Facilities, existing Facilities, modifications to existing Facilities and re-ratings of existing Facilities.

M2. The Transmission Owner and Generator Owner shall each have evidence that it provided its Facility Ratings to its associated Reliability Coordinator(s), Planning Authority(ies), Transmission Planner(s), and Transmission Operator(s) as scheduled by such requesting entities.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Regional Reliability Organization

   1.2. Compliance Monitoring Period and Reset Time Frame

   Each Transmission Owner and Generator Owner shall self-certify its compliance to the Compliance Monitor annually. The Compliance Monitor may conduct a targeted audit once in each calendar year (January–December) 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 Transmission Owner and Generator Owner 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 retain audit data for three years.

1.4. Additional Compliance Information

The Transmission Owner and Generator Owner 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 Facility Ratings Methodology

1.4.2 Facility Ratings

1.4.3 Evidence that Facility Ratings were distributed

1.4.4 Distribution schedules provided by entities that requested Facility Ratings

2. Levels of Non-Compliance

2.1. Level 1: Not all requested Facility Ratings associated with existing Facilities were provided to the Reliability Coordinator(s), Planning Authority(ies), Transmission Planner(s), and Transmission Operator(s) in accordance with their respective schedules.

2.2. Level 2: Not all Facility Ratings associated with new Facilities, modifications to existing Facilities, and re-ratings of existing Facilities were provided to the Reliability Coordinator(s), Planning Authority(ies), Transmission Planner(s), and Transmission Operator(s) in accordance with their respective schedules.

2.3. Level 3: Facility Ratings provided were not developed consistent with the Facility Ratings Methodology.

2.4. Level 4: No Facility Ratings were provided to the Reliability Coordinator(s), Planning Authority(ies), Transmission Planner(s), or Transmission Operator(s) in accordance with their respective schedules.

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

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. SAC approves SAR for posting (March 20, 2002).
2. Drafting Team posts Draft SAR for comment periods (April 2–May 3, 2002) (September 24–October 25, 2002) (December 13–January 31, 2003).
3. SAC approves development of standard (February 27, 2003).
4. JIC assigns development of standard to NERC (March 21, 2003)
5. Drafting team posts drafts for comment (July 1–August 29, 2003) (December 1–January 21, 2004) (February 18–April 3, 2005).
6. Drafting team posts Implementation Plan for comment (June 1–July 15, 2005).
7. Drafting team posts draft for 30-day pre-ballot review (September 1–30, 2005).
8. First ballot conducted October 1–10, 2005 but failed due to lack of quorum.
9. Re-ballot conducted from October 18–November 8, 2005.
10. Drafting team posts revised definition of Contingency for comment (December 1, 2005–January 17, 2006).

Description of Current Draft:

There was no consensus to support the drafting team's revised definition of 'Contingency' and the drafting team has reverted to accepting the definition of contingency that was approved with Version 0 standards. The drafting team is posting FAC-010 for a 30-day, pre-ballot review from February 15 through March 16, 2006.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Conduct first ballot.	March 20–30, 2006
2. Consider comments submitted with first ballot; post consideration of comments.	April 3–7, 2006
3. Conduct first ballot.	April 10–20, 2006
4. Post standards and implementation plan for 30-day review by board.	April 1, 2006
5. Board adoption date.	May 2, 2006
6. Proposed effective date.	Six months after BOT adoption

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.

Cascading Outages: The uncontrolled successive loss of Bulk Electric System Facilities triggered by an incident (or condition) at any location resulting in the interruption of electric service that cannot be restrained from spreading beyond a pre-determined area.

Delayed Fault Clearing: Fault clearing consistent with correct operation of a breaker failure protection system and its associated breakers, or of a backup protection system with an intentional time delay.

Interconnection Reliability Operating Limit (IROL): A System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading Outages that adversely impact the reliability of the Bulk Electric System.

Interconnection Reliability Operating Limit T_v (IROL $T_{v)}$: The maximum time that an Interconnection Reliability Operating Limit can be violated before the risk to the interconnection or other Reliability Coordinator Area(s) becomes greater than acceptable. Each Interconnection Reliability Operating Limit's T_v shall be less than or equal to 30 minutes.

Normal Clearing: A protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems.

A. Introduction

1. **Title:** **System Operating Limits Methodology**

2. **Number:** FAC-010-1

3. **Purpose:** To ensure that System Operating Limits (SOLs) 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

   4.2. Planning Authority

5. **Proposed Effective Date:** Six months after BOT adoption

B. Requirements

R1. The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area. This SOL Methodology shall:

R1.1. Be applicable for developing SOLs used in the operations horizon.

R1.2. State that SOLs shall not exceed associated Facility Ratings.

R1.3. Include a description of how to identify the subset of SOLs that qualify as IROLs.

R2. The Planning Authority shall have a documented SOL Methodology for use in developing SOLs within its Planning Authority Area. This SOL Methodology shall:

R2.1. Be applicable for developing SOLs used in the planning horizon.

R2.2. State that SOLs shall not exceed associated Facility Ratings.

R2.3. Include a description of how to identify the subset of SOLs that qualify as IROLs.

R3. The Reliability Coordinator and Planning Authority shall, by mutual agreement[1], identify and document in their respective SOL Methodologies the planning and operating time horizons addressed in one another's SOL Methodologies.

R3.1. The combined horizons shall cover real-time through the end of the planning horizon.

R4. The Reliability Coordinator's SOL Methodology and the Planning Authority's SOL Methodology shall each include a requirement that SOLs provide BES performance consistent with the following:

R4.1. In the pre-contingency state, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages.

[1] If mutual agreement cannot be reached, the planning horizon shall be one year and beyond and the operating horizon shall be real-time up to one year.

R4.2. Following the single Contingencies[2] identified in FAC-010 Requirement 4.2.1 through Requirement 4.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading Outages or uncontrolled separation shall not occur.

R4.2.1. Single line to ground or 3-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.

R4.2.2. Loss of any generator, line, transformer, or shunt device without a Fault.

R4.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.

R4.3. In determining the system's response to a single Contingency, the following shall be acceptable:

R4.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.

R4.3.2. Interruption of other network customers, only if the system has already been adjusted, or is being adjusted, following at least one prior outage[3], or, if the real-time operating conditions are more adverse than anticipated in the corresponding studies, e.g., load greater than studied.

R4.3.3. System reconfiguration through manual or automatic control or protection actions.

R4.4. To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.

R4.5. Following a Regional Reliability Organization identified credible multiple Contingency, the system shall meet criteria established by the Region for that Contingency.

R5. The Reliability Coordinator's methodology and the Planning Authority's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:

R5.1. Area of study (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.)

R5.2. Selection of applicable Contingencies

R5.3. Level of detail of system models used to determine SOLs

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[2] The Contingencies identified in FAC-010 R4.2.1 through R4.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.

[3] An intact system must be able to supply all network customers other than those identified in FAC-010 Requirement 4.3.1 after any single Contingency identified in FAC-010 R4.2. Thus, interruption of such network customers as a response to any single Contingency is not acceptable for a SOL, as developed by a Reliability Coordinator for a system intact condition in the operating horizon or a SOL, as developed by a Planning Authority, for a system intact condition in the planning horizon.

R5.4. Allowed uses of Special Protection Systems or Remedial Action Plans

R5.5. Anticipated transmission system configuration, generation dispatch and Load level

R5.6. Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_v.

R6. The Reliability Coordinator shall issue its SOL Methodology and any changes to that methodology, to all of the following:

R6.1. Each adjacent Reliability Coordinator and each Reliability Coordinator that indicated it has a reliability-related need for the methodology.

R6.2. Each Planning Authority and Transmission Planner that models any portion of the Reliability Coordinator's Reliability Coordinator Area.

R6.3. Each Transmission Operator that operates in the Reliability Coordinator Area.

R7. The Planning Authority shall issue its SOL Methodology, and any change to that methodology, to all of the following:

R7.1. Each adjacent Planning Authority and each Planning Authority that indicated it has a reliability-related need for the methodology.

R7.2. Each Reliability Coordinator and Transmission Operator that operates any portion of the Planning Authority's Planning Authority Area.

R7.3. Each Transmission Planner that works in the Planning Authority's Planning Authority Area.

R8. The Reliability Coordinator and Planning Authority shall each issue its SOL Methodology and any changes to that methodology to required entities prior to the effectiveness of the change.

R9. If a recipient of the SOL 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 SOL Methodology and, if no change will be made to that SOL Methodology, the reason why.

C. Measures

M1. The Reliability Coordinator and the Planning Authority's SOL Methodology shall each include a statement that Facility Ratings shall not be exceeded and shall address all of the items listed in FAC-010 Requirement 3 through Requirement 5.

M2. The Reliability Coordinator shall have evidence it issued its SOL Methodology, and any changes to that methodology, including the date they were issued, in accordance with FAC-010 Requirement 6.

M3. The Planning Authority shall have evidence it issued its SOL Methodology and any changes to that methodology, including the date they were issued, in accordance with FAC-010 Requirement 7.

M4. If the recipient of the SOL Methodology provides documented comments on its technical review of that SOL methodology, the Reliability Coordinator or Planning Authority that distributed that SOL Methodology shall have evidence that it provided a written response to that commenter within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

Each Planning Authority and Reliability Coordinator shall self-certify its compliance to the Compliance Monitor at least once every three years. New Planning Authorities and Reliability Authorities 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 non-compliance.

1.3. Data Retention

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

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 SOL Methodology.

1.4.2 Documented comments provided by a recipient of the SOL Methodology on its technical review of a SOL Methodology, and the associated responses.

1.4.3 Superseded portions of its SOL Methodology that had been made within the past 12 months.

1.4.4 Evidence that the SOL Methodology and any changes to the methodology that occurred within the past 12 months were issued to all required entities.

2. Levels of Non-Compliance (Does not apply to the Western Interconnection)

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

2.1.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.

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

2.2. Level 2: The SOL Methodology did not include a requirement to address all of the elements in FAC-010 R4.

2.3. Level 3: There shall be a level three non-compliance if either of the following conditions exists:

2.3.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded **and** the methodology did not include a requirement for evaluation of system response to one of the three types of single Contingencies identified in FAC-010 R4.2.

2.3.2 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded **and** the methodology did not address two of the six required topics in FAC-010 R5.

2.4. Level 4: The SOL Methodology was not issued to all required entities in accordance with FAC-010 R6 and R7.

3. Levels of Non-Compliance for Western Interconnection:

3.1. Level 1: The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.

3.2. Level 2: The SOL Methodology did not include a requirement to address all of the elements in FAC-010 R4 and FAC-010 E1.

3.3. Level 3: There shall be a level three non-compliance if any of the following conditions exists:

3.3.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to one of the three types of single Contingencies identified in FAC-010 R4.2.

3.3.2 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to two of the seven types of multiple Contingencies identified in FAC-010 E1.1.

3.3.3 The System Operating Limits Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not address two of the six required topics in FAC-010 R5.

3.4. Level 4: The SOL Methodology was not issued to all required entities.

E. Regional Differences

1. The following Interconnection-wide Regional Difference shall be applicable in the Western Interconnection:

1.1. As governed by the requirements of FAC-010, R4.5 shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:

1.1.1 Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.

1.1.2 A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in FAC-010 E1.1.7

1.1.3 Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.

1.1.4 The failure of a circuit breaker associated with a Special Protection System to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.

1.1.5 A non-three phase Fault with Normal Clearing on common mode Contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.

1.1.6 A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-010.

1.1.7 The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground Fault.

1.2. SOLs shall be established such that for multiple Facility Contingencies in FAC-010 E1.1.1 through FAC-010 E1.1.5 operation within the SOL shall provide system performance consistent with the following:

1.2.1 All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.

1.2.2 Cascading Outages do not occur.

1.2.3 Uncontrolled separation of the system does not occur.

1.2.4 The system demonstrates transient, dynamic and voltage stability.

1.2.5 Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (Load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.

1.2.6 Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.

1.2.7 To prepare for the next Contingency, system adjustments are permitted, including changes to generation, Load and the transmission system topology when determining limits.

1.3. SOLs shall be established such that for multiple Facility Contingencies in FAC-010 E1.1.6 through FAC-010 E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:

1.3.1 Cascading Outages do not occur.

1.4. The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to Contingencies for specific facilities based on actual system performance and robust design. Such changes will apply in determining SOLs.

Version History

Version	Date	Action	Change Tracking
1	02/03/06	Page 8, Regional Differences, corrected end of sentence from "FAC-008" to "FAC-010."	03/20/06

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. SAC approves SAR for posting (March 20, 2002).
2. Drafting team posts draft SAR for comment periods (April 2–May 3, 2002) (September 24–October 25, 2002) (December 13–January 31, 2003).
3. SAC approves development of standard (February 27, 2003).
4. JIC assigns development of standard to NERC (March 21, 2003).
5. Drafting team posts drafts for comment (July 1–August 29, 2003) (December 1–January 21, 2004) (February 18–April 3, 2005).
6. Drafting team posts Implementation Plan for comment (June 1–July 15, 2005).
7. Drafting team posts draft for 30-day, pre-ballot review (September 1–30, 2005).
8. First ballot conducted October 1–10, 2005 but failed due to lack of quorum.
9. Re-ballot conducted from October 18–November 8, 2005.
10. Drafting team posts revised definition of Contingency with FAC-010 for comment (December 1, 2005–January 17, 2006) and holds back on balloting FAC-011 until stakeholders review the revised definition.

Description of Current Draft:

There was no consensus to support the drafting team's revised definition of 'Contingency' and the drafting team has reverted to accepting the definition of contingency that was approved with Version 0 standards. The drafting team is posting FAC-011 for a 30-day pre-ballot review from February 15 through March 16, 2006.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Conduct first ballot.	March 20–30, 2006
2. Consider comments submitted with first ballot; post consideration of comments.	April 3–7, 2006
3. Conduct second ballot.	April 10–20, 2006
4. Post standards and implementation plan for 30-day review by board.	April 1, 2006
5. Board adoption date.	May 2, 2006
6. Proposed effective date.	Eight months after BOT adoption

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.

None introduced in this standard.

A. Introduction

1. **Title:** **Establish and Communicate System Operating Limits**
2. **Number:** FAC-011-1
3. **Purpose:** To ensure that System Operating Limits (SOLs) 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
    - **4.2.** Planning Authority
    - **4.3.** Transmission Planner
    - **4.4.** Transmission Operator
5. **Proposed Effective Date:** Eight months after BOT adoption

B. Requirements

R1. The Reliability Coordinator shall ensure that SOLs, including Interconnection Reliability Operating Limits (IROLs), for its Reliability Coordinator Area are established and that the SOLs (including Interconnection Reliability Operating Limits) are consistent with its SOL Methodology.

R2. The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology.

R3. The Planning Authority shall establish SOLs, including IROLs, for its Planning Authority Area that are consistent with its SOL Methodology.

R4. The Transmission Planner shall establish SOLs, including IROLs, for its Transmission Planning Area that are consistent with its Planning Authority's SOL Methodology.

R5. The Reliability Coordinator, Planning Authority and Transmission Planner shall each provide its SOLs and IROLs to those entities that have a reliability-related need for those limits and provide a written request that includes a schedule for delivery of those limits as follows:

R5.1 The Reliability Coordinator shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Reliability Coordinators and Reliability Coordinators who indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, Transmission Service Providers and Planning Authorities within its Reliability Coordinator Area. For each IROL, the Reliability Coordinator shall provide the following supporting information:

R5.1.1 Identification and status of the associated Facility (or group of Facilities) that is (are) critical to the derivation of the IROL.

R5.1.2 The value of the IROL and its associated T_v.

R5.1.3 The associated Contingency(ies).

R5.1.4 The type of limitation represented by the IROL (e.g., voltage collapse, angular stability).

R5.2 The Transmission Operator shall provide any SOLs it developed to its Reliability Coordinator and to the Transmission Service Providers that share its portion of the Reliability Coordinator Area.

R5.3 The Planning Authority shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Planning Authorities, and to Transmission Planners, Transmission Service Providers, Transmission Operators and Reliability Coordinators that work within its Planning Authority Area.

R5.4 The Transmission Planner shall provide its SOLs (including the subset of SOLs that are IROLs) to its Planning Authority, Reliability Coordinators, Transmission Operators, and Transmission Service Providers that work within its Transmission Planning Area and to adjacent Transmission Planners.

C. Measures

M1. The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each be able to demonstrate that it developed its SOLs (including the subset of SOLs that are IROLs) consistent with the applicable SOL Methodology.

M2. The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each have evidence that its SOLs (including the subset of SOLs that are IROLs) were supplied in accordance with schedules supplied by the requestors of such SOLs.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each verify compliance through self-certification submitted to its 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 performance.

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

1.3. Data Retention

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

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

1.4. Additional Compliance Information

The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner 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 SOL Methodology(ies)

1.4.2 SOLs, including the subset of SOLs that are IROLs and the IROL's supporting information

1.4.3 Evidence that SOLs were distributed

1.4.4 Distribution schedules provided by entities that requested SOLs

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: Not all SOLs were provided in accordance with their respective schedules.

2.3. Level 3: SOLs provided were not developed consistent with the SOL Methodology.

2.4. Level 4: No SOLs were provided in accordance with their respective schedules.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking

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

Difference of Network Response Methodologies among Transmission Providers

The purpose of this paper is to help members of the Standard Drafting understand the differences in network response methodologies in the east and try to identify areas that could be standardized.

Generally, transmission service providers in the eastern interconnection use a network response methodology but there are various differences in the methodology that could be standardized. The following items in the methodology are things that are not done consistently throughout the eastern interconnection:

- AFC vs. ATC (Flowgates vs. FCITC)
- Simultaneous vs. Non-simultaneous
- Sources/Sinks
- Inclusion of Internal and External Data
  - Reservations/schedules
    - Flow/Counter-flow
  - Outage data
  - Generation Dispatch Data
  - Respect of third party AFC Data
- Margins (TRM,CBM)
- Others

AFC vs. ATC

Both Available Flowgate Capability (AFC) and Available Transfer Capability (ATC) use the same basic calculation:

Transmission Available to sell from A to B =
(Rating of Monitored Facility - (Contingent Element Flow * Line Outage Distribution Factor) – Existing Committed Flow on Monitored Facility)/ (Distribution Factor of Transaction from A to B on Monitored Facility).

If there is no contingency, the LODF = 0 and the distribution factor is the power transfer distribution factor and if there is a contingency, the distribution factor of the transaction would be the outage transfer distribution factor. Somewhere in the calculation, a margin or margins are subtracted from what is available. Some providers subtract the margins without dividing it from the distribution factor while others do.

The Available Flowgate Capability (AFC) methodology focuses on determining the amount of service available on each monitored facility that could be the limiting facility for a transfer. The data that is posted to the OASIS would be the (Rating of Monitored Facility - (Contingent Element Flow * Line Outage Distribution Factor) – Existing Committed Flow on Monitored Facility). When evaluating a request, the distribution factors are calculated on all flowgates and the most limiting one determines the amount of service sold. The sharing of data with neighbors and allowing them to honor your limits is easier if you send them all of your AFC data for all horizons. The inconsistency occurs when the other transmission service provider calculates a different distribution factor on that flowgate and will sell more or less service.

The ATC methodology focuses on the path, which finds the most limiting facility, based on the facilities monitored, but this is more difficult to share data with your neighbors and allow your neighbors to honor your transmission limitations. The OASIS posting is the ATC from A to B.

There also may be other implementations of ATC methodology.

Simultaneous vs. Non-simultaneous

Most of the ATC postings are non-simultaneous numbers and the selling of service on one path may decrease or even increase the service available on another path. At lease on entity may be calculating the amount of total import capability into an area can be accommodated and then spreading that total capability across multiple paths in some fashion to be a simultaneous posting.

AFC values are decremented when any service is sold (or maybe when requested, study mode or accepted). Therefore it takes into account the simultaneous nature of service that is sold.

Sources/Sinks

Sources and sinks used to calculate the distribution factors of a transaction are a very critical piece in the calculation of ATC or AFC.

Source points could be generalized into the following four categories:

1. Increase generation level of an individual unit or units at a station
2. Increase generation level of a group of units that represent a system dispatch
3. Load Reduction (if there is no available generation in the source system)
4. A combination of increasing generation and reducing load

Sink points could be generalized into the following four categories:

1. Decrease generation level of an individual unit or units at a station
2. Decrease generation level of a group of units that represent a system dispatch
3. Load increase when the sink area is not at projected peak
4. A combination of decreasing generation and increasing load

There is no standard way of developing sources or sinks throughout the eastern interconnection and there is also no standard if the source and sink should be one tier away from the transmission provider or if it should try to reflect the actual source or sink or if electrical equivalents are allowed to be used. When transactions can occur from Minnesota to Georgia, the calculated distribution factors on monitored facilities can be extremely different than a first-tier distribution factor.

This also directly relates to the tags and which transmission service is allowed to be used on energy transaction tags. Some transmission providers only sell service to/from tier-one entities, but allow the tag to be to/from any GCA or LCA as long as the path of the transaction goes through that particular source/sink listed on the transmission service reservation. Other providers require that the control areas on the transmission service reservation must match the GCA and LCA on the tag exactly or the tag is not allowed to flow.

Inclusion of Internal and External Data

Some providers are constantly updating reservations sold under other tariffs and update their models and some don't. Also at some point, some providers use schedules and don't include reservations. When providers do include reservations (their own or others) they may include 100% flow/counter-flow or some percentage of each to the extreme of 100% flow and 0% counter-flow.

Another inconsistent use of data is outage data. Some providers may include generation or transmission outages of their own system but use little or no outage data external to the footprint, while others try to include all known data.

Once providers begin using generation data of external entities, there is an inconsistency on how to dispatch that external entity. Some providers use updated load forecasts and generation dispatch data from that external entity, but some do not.

Another important piece of data that is inconsistently used is the AFC data of third party providers. Some providers may say they are honoring third party limitations, but only monitor those facilities and base the availability of service on their own model and do not use the AFC of the owner of the facility. Also, different providers could be using the AFC of a third party and evaluate a request from the same source control area to the same sink control area, but one may approve the service, but another may not. The reason could be that the way distribution factors are created and how they define the sources and sinks. It also may depend on the distribution factor cut-offs that are being used.

Margins

Some providers use CBM, while others don't and the methodology to calculate CBM can be very subjective. TRM is also a very subjective calculation and varies by provider.

Others

In St. Louis, we can at least make sure people have an understanding of the differences and we can add to this list.

of FPA section 211A. Further, as we indicate below, we expect unregulated transmission providers to participate in the open and transparent regional planning processes that we propose to order and note that, if there are complaints about such participation, we will address them on a case-by-case basis.

112. We disagree with the position of the Canadian Electricity Association. EPAct 2005 did not repeal the reciprocity obligation in Order No. 888. Rather, it granted a new avenue of authority to the Commission to order comparable transmission service from non-public utilities. We are proposing not to exercise this new authority at this time. Rather, we are proposing to retain our reciprocity policy, which was adopted pursuant to sections 205 and 206 of the FPA. By maintaining the same reciprocity requirement for domestic, non-public utilities as for foreign utilities doing business in the United States, the Commission will ensure that foreign entities will continue to be treated no less favorably than domestic, non-public utilities.

V. Proposed Modifications of the OATT

A. Consistency and Transparency of ATC Calculations

113. In Order Nos. 888 and 889, the Commission directed transmission providers to offer their unused transfer capability to the market and to post the amount of ATC[107] on OASIS. At the time those orders were issued, the Commission noted that formal methods did not exist for calculating ATC, but recognized that there were industry efforts

[107] See supra note 7.

underway to develop a consistent, industry-wide method for calculating it.[108] Instead of prescribing a specific methodology for calculating ATC in Order Nos. 888 and 889, the Commission encouraged the industry efforts and required that transmission providers base their ATC calculation methodologies on current industry practices, standards and criteria.[109] In addition, the Commission directed transmission providers to include a description of their ATC calculation methodologies in Attachment C of their tariffs.

114. Ten years later, however, although some progress has been made, the industry still has not developed a consistent, industry-wide methodology for evaluating ATC. In the intervening years, the industry, working through the North American Electric Reliability Council (NERC), has adopted a general definition of ATC, which establishes a basic methodology for evaluating ATC. NERC also has developed a set of guiding principles for calculating ATC and has encouraged further consistency of ATC calculation methodologies on a regional level. NERC defines ATC as the transfer capability remaining on the system for further commercial activity over and above already committed uses. This value is determined by deducting existing transmission commitments (ETC)[110] (including transmission reservations, network and retail customer

[108] Order No. 889 at 31,607.

[109] Id.

[110] NERC does not have a formal definition or standard methodology for ETC.

service), capacity benefit margin (CBM),[111] and transmission reliability margin (TRM)[112] from total transfer capability (TTC).[113] However, NERC's calculation methodology is not prescriptive; it establishes a framework for evaluating ATC, which leaves open to each transmission provider's interpretation and discretion the specific algorithm, data inputs and assumptions needed to assess ATC.[114] Consequently, transmission providers

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[111] NERC defines CBM as the amount of firm transmission transfer capability preserved by the transmission provider for load-serving entities, whose loads are located on that transmission service provider's system, to enable access by the load-serving entities to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for a load-serving entity allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission transfer capability preserved as CBM is intended to be used by the load-serving entities only in times of emergency generation deficiencies. See North American Electric Reliability Council, Glossary of Terms Used in Reliability Standards, (Effective April 1, 2005), (NERC Glossary) available at ftp://www.nerc.com/pub/sys/all_updl/standards/sar/Glossary_07Feb06.pdf.

[112] NERC defines TRM as the amount of transmission transfer capability necessary to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change. See NERC Glossary.

[113] NERC defines TTC as 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. See NERC Glossary.

[114] See NERC, Available Transfer Capability Definitions and Determination: A Framework for Determining Available Transfer Capabilities of the Interconnected Transmission Networks for a Commercially Viable Electricity Market (1996) available at ftp://ftp.nerc.com/pub/sys/all_updl/docs/pubs/atcfinal.pdf.

have developed numerous ways to evaluate ATC using their own algorithms, data and modeling assumptions.[115]

115. Although transmission providers across the Nation have developed various methodologies, in general, there are two main approaches to calculating ATC used in the industry. The first is the contract path approach, which is more commonly used by transmission providers in the Western Electricity Coordinating Council (WECC) region.[116] The contract path methodology derives ATC directly from predetermined TTC, ETC, CBM, and TRM values derived consistent with contract path transmission rights. The second method is the flowgate[117] approach, which is used more widely in the Eastern Interconnection.[118] The flowgate methodology is based on physical power flow models. The flowgate calculation first determines AFC and then converts AFC into ATC and derives TTC for the OASIS posting. The differences between the two approaches

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[115] See supra note 59.

[116] See, e.g., Determination of Available Transfer Capability within the Western Interconnection (June 2001), available at http://www.wecc.biz/documents/library/procedures/ATC-apprdec01.pdf.

[117] A flowgate is a designated point on the transmission system used in the modeling of power flows. While NERC currently does not have a formal definition for AFC, the power industry commonly defines AFC as a measure of the capability remaining on a flowgate for future uses, after considering the effect of prior sales. Mathematically, the industry measures AFC as AFC = Flowgate rating – [(base case flow) – (impacts of existing reservations)] – Flowgate $_{CBM}$ –Flowgate $_{TRM}$.

[118] See, e.g., PJM Manual 2: Transmission Service Request (April 14, 2005), available at: http://www.pjm.com/contributions/pjm-manuals/pdf/m02v08.pdf

may not result in significantly different ATC values if consistent data inputs and industry acceptable modeling assumptions are used. Without a consistent and transparent approach to evaluating ATC, transmission customers will remain wary when service is denied and transmission providers will be the subject of suspicion and heightened scrutiny, especially given the increasingly congested state of the Nation's electric grid.

Consistency

116. Generally, transmission providers calculate ATC by creating a base model of their system using a set of data inputs and assumptions, which are determined by the transmission provider. The transmission provider uses the model to perform various computer simulations of the operations of its system to determine the levels of transfer capability available on the system. The types of data and assumptions used in the models include, for example, facility ratings, the operating status of facilities, and generation dispatch, which might be supported by history, transmission plans, or the judgment of the transmission provider. For example, a transmission provider could use its judgment to reduce a facility rating or model certain facilities as out of service, which would have the effect of calculating a lower TTC value. A transmission provider also may use generation dispatch assumptions to limit transfer capability that otherwise would have been available to independent generators, thereby favoring the transmission provider's own generation. A transmission provider usually assumes that designated network resources are dispatched in economic merit order. However, a transmission provider has the discretion to decide which of the generators that are not designated network resources

will be modeled in-service. Assumptions like these influence the loading on transmission lines in the model and heavily influence the resulting ATC. Having standards in place that address the calculation of ATC components, data inputs, and modeling assumptions would help ensure non-discriminatory treatment by limiting a transmission provider's ability to use discretion to the disadvantage of competitors and the market.

117. As noted above, NERC does not have a formal definition of ETC. Without clear criteria for what should be included in a transmission provider's ETC, a transmission customer might not know whether ETC is being over- or underestimated. For example, a transmission provider could set aside more capacity for native load than is realistically expected to occur. This could happen if a transmission provider includes in ETC excess capacity for a load-serving entity (such as capacity to meet generation reserve requirements) but then also has a CBM component in its calculation of ATC that includes the same capacity. A transmission provider also could overestimate its ETC by double-counting the same transmission reservations in its ATC calculation. For example, this could happen if a transmission provider fails to replace a transmission reservation with the associated real-time schedule, and as a result does not release non-firm ATC. A consistent process for calculating ETC will limit the subjectivity of the transmission provider's decisions and provide a more uniform method for estimating ETC.

118. With respect to the modeling of a particular transaction, when information concerning the source is unknown, a transmission provider has the discretion to select

which generator(s) will be used as a source.[119] There are no standards for how that modeling should be done and, consequently, a transmission provider could model a source using single or multiple generators by increasing (scaling up) their output. In general, modeling a transaction using multiple generators as a source is less conservative for the transmission system than modeling a transaction using a single generator as a source. Modeling a transaction using multiple generators as a source typically results in a higher ATC value. Conversely, when a transmission provider models a transaction using a single generator as a source, this can result in a lower ATC value depending on the location of the generator. Modeling of contingency outages used for calculating ATC is another area within the discretion of the transmission provider. Although the type of contingency, such as single contingency (n-1), is determined by governing reliability criteria,[120] the transmission provider determines which specific contingencies will be used for the ATC calculation. The common industry practice is to consider the loss of each transmission facility at voltage 100 kV and above. However, the lack of standards governing transfer analysis allows the transmission provider to use its discretion to

[119] Transmission providers do not always know the generator used as a source of energy provided under contracts that qualify as designated resources; the only requirement is that the network customer have an executed contract that commits it to purchase noninterruptible power. See Wisconsin Public Power Inc. v. Wisconsin Public Service Corp., 84 FERC ¶ 61,120 at 61,650-51 (1998).

[120] Standard TPL-001-0, Table I. Transmission System Standards – Normal and Emergency Conditions, NERC Reliability Standards for the Bulk Electric Systems of North America (effective April 1, 2005).

monitor outages only of facilities at 230 kV and above, ignoring the limitations that may exist for the loss of the facilities at lower voltages, such as 115 kV or 138 kV. Consequently, ATC values may vary substantially, with ATC being much higher when monitoring contingencies of facilities at 230 kV and above, and much lower while monitoring the loss of all facilities (voltage 100 kV and above).

119. Furthermore, in calculating ATC, transmission providers set aside a portion of transfer capability in the form of CBM and/or TRM to provide for adequate generation reserves and account for uncertainties or contingencies, respectively. Generally, CBM is the amount of firm transmission transfer capability held back by the transmission provider so that load-serving entities, whose loads are located on the transmission provider's system, can access remote generation reserve from interconnected systems in times of emergency generation deficiencies. Some believe it is necessary for transmission providers to set aside a portion of their TTC to ensure that their ties with other systems remain available for this purpose. There are no consistent industry-wide standards, however, for determining how much transfer capability should be set aside as CBM. There is also no common approach to whether the capacity is set aside for Native Load Customers, as defined in section 1.19 of the pro forma OATT, for retail load, or for all load-serving entities. The lack of consistent criteria and clarity with regard to the entity on whose behalf CBM has been set aside has the potential to result in the transmission provider setting aside capacity that it might not otherwise need to, thus

increasing costs for native load customers and blocking other firm uses of the transmission system.[121]

120. Similarly, TRM is the amount of transmission transfer capability reserved by the transmission provider to ensure that the transmission network will be secure under a reasonable range of uncertainties in system conditions. Because TRM and CBM are both maintained in part for the loss of generators, there exists the possibility of double-counting reliability margins for the loss of the same generation.

121. Moreover, a transmission provider also can use more conservative inputs and assumptions for calculating ATC and performing system impact studies (that tend to minimize ATC) when it is assessing a long-term transmission service request, but use less conservative inputs and assumptions (that tend to maximize ATC) when it is performing system planning for retail native load. This creates the potential for undue discrimination where a transmission provider uses one set of data and assumptions to evaluate third party requests and another set of data and assumptions to plan its system to serve its own load.

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[121] The Commission has explained that the pro forma OATT requires both transmission customers and transmission providers using the transmission system to serve network load (including bundled retail native load) to designate their resources and loads so that the transmission customers and transmission providers would have no incentive to designate network resources above their needs and, in so doing, tie up valuable transmission capacity. Aquila Power Corp. v. Entergy Services, Inc., 90 FERC ¶ 61,260, reh'g denied, 92 FERC ¶ 61,064 (2000), reh'g denied, 101 FERC ¶ 61,328 (2002), aff'd sub nom. Entergy Services, Inc. v. FERC, 375 F.3d 1204 (D.C. Cir. 2004) (Aquila).

Data Exchange Among Transmission Providers

122. The lack of a consistent ATC calculation methodology combined with limited coordination between transmission providers can result not only in inefficiencies but unjust and unreasonable terms and conditions of service, especially for a customer seeking contiguous transmission service from multiple transmission providers. The ATC values posted by a transmission provider are often inaccurate for reasons beyond the control of the transmission provider. A transmission provider may post ATC values in good faith and attempt to provide transmission service based on these values only to discover later that the transfer capability that it thought was available no longer exists due to decisions made by other transmission providers that it did not know about at the time it made its calculations. Accurate ATC calculation requires reliable and timely information about such things as load, generation dispatch, facility outages, and transactions on neighboring systems. Transmission providers also may apply differing assumptions and criteria to ATC calculations, which may produce wide variations in posted ATC values for the same transmission paths. All of these considerations make it difficult for an individual transmission provider that operates one part of an interconnected grid to calculate ATC accurately.

123. This lack of communication and coordination between transmission providers of ATC data can also affect reliability. As discussed above, a transmission provider could grant transmission service without being aware of the real impact that service may have on an adjacent transmission provider's system, thus degrading the reliability of the

interconnected system. Inaccurate ATC values can cause overselling of transfer capability, which can lead to curtailments or transmission loading relief (TLR) actions to avoid exceeding thermal, voltage, and/or stability limits.

<u>Transparency</u>

124. As discussed, the lack of a consistent, industry-wide methodology for assessing ATC makes undue discrimination difficult to detect. This problem is further exacerbated by a lack of transparency surrounding the calculation methodology used by transmission providers. Although the Commission requires transmission providers to file their methodologies for calculating ATC in their tariffs, transmission providers often have responded by filing very general narrative descriptions of their calculation methodologies (often simply referring to the general NERC definition)[122] without further specification of the mathematical algorithm, data inputs, and modeling assumptions used to perform the calculation.

125. Other than the description of the ATC methodology provided in transmission providers' tariffs, third parties often have limited access to information concerning the specific algorithms, data and assumptions used by transmission providers to evaluate their ATC, which makes it difficult to verify or challenge a transmission provider's ATC calculations. The Commission requires each transmission provider to calculate and post

[122] <u>See, e.g.</u>, the OATTs of Aquila, Inc., Southern, and Tucson Electric Power Company.

ATC and TTC values for each posted path.[123] Transmission providers also are required to make publicly available, on request, all data used to calculate ATC and TTC for any constrained path.[124] Additionally, transmission providers are required to make publicly available, on request, system planning studies or network impact studies performed for customers to determine network impacts. Furthermore, subsequent to Order Nos. 888 and 889, the Commission required each transmission provider to post (and update) the CBM value for each path for which it already posts ATC and TTC, as well as a narrative explanation of its CBM practices. [125]

126. Yet, despite these requirements, third parties often are unable to gain access to sufficient information surrounding a transmission provider's ATC calculation methodology. As a preliminary matter, we note that while the OASIS requirements regarding the availability of information related to ATC and TTC calculations are still in effect, they have been affected by restrictions that have been placed upon the availability

[123] See 18 CFR 37.6 (b) (2005). A posted path is defined as any control area to control area interconnection; any path for which service is denied, curtailed or interrupted for more than 24 hours in the past 12 months; and any path for which a customer requests to have ATC or TTC posted. Id. 37.6 (b)(1)(i).

[124] Id. 37.6 (b)(2)(ii). A constrained posted path is defined as any posted path having an ATC value less than or equal to 25 percent of TTC at any time during the preceding 168 hours or for which ATC has been calculated to be less than or equal to 25 percent of TTC for any period during the current hour or the next 168 hours. Id. 37.6 (b)(1)(ii).

[125] Capacity Benefit Margin in Computing Available Transmission Capacity, 88 FERC ¶ 61,099 (1999) (CBM Order).

of critical energy infrastructure information (CEII) in the interest of national security.[126] Therefore, system planning and network impact studies and models typically are no longer available on a transmission provider's OASIS. Furthermore, transmission customers are often unable to access other information such as load flow base cases and associated files. In sum, although existing Commission regulations are intended to provide a certain level of transparency, this transparency is undermined by a number of factors, including the absence of detailed descriptions of the data inputs, assumptions, and criteria used to determine the data included in ATC calculations, as well as the inability of customers to access certain of this data because of, among other reasons, security concerns.

Recent Industry Efforts to Improve the Consistency and Transparency of ATC Calculations

127. The industry recently has taken some steps to address the lack of consistency and transparency in the way ATC is calculated. NERC formed a Long-Term AFC/ATC Task Force to review NERC's standards on ATC, which issued a final report in 2005 (NERC Report)[127] that made recommendations for greater consistency and greater clarity in the

[126] See Critical Energy Infrastructure Information, Order No. 630, 68 FR 9857 (Mar. 3, 2003), FERC Stats. & Regs. ¶ 31,140 (2003), order on reh'g, Order No. 630-A, 68 FR 46456 (Aug. 6, 2003), FERC Stats. & Regs. ¶ 31,147 (2003), order on clarification, Order No. 662, 70 FR 37031 (Jun. 28, 2005), FERC Stats. & Regs. ¶ 31,189 (2005); see also 18 CFR 388.113 (2005).

[127] See supra note 115.

calculation of ATC. The task force also recommended greater communication and coordination of ATC information to ensure that neighboring entities exchange relevant information. Based on the recommendations in the NERC Report, NERC has two Standards Authorization Request (SAR) proceedings underway to revise the standards on ATC. The first SAR proceeding proposes changes to the existing standards on ATC to, among other things, further establish consistency (on a regional basis) in the calculation of ATC and to increase the clarity of each transmission provider's ATC calculation methodology. The second SAR proceeding proposes certain changes to NERC's existing standards on the ATC components of CBM and TRM. This proceeding also calls for greater regional consistency and transparency in how CBM and TRM are treated in transmission providers' ATC calculations. Also, based on the recommendations in the NERC Report, the North American Energy Standards Board (NAESB) has a proceeding underway to develop business practice standards to enhance the processing of transmission service requests, which use TTC, ATC and/or AFC.

128. Following the release of the NERC Report, the Commission issued the ATC NOI[128] seeking comments on the contents of the NERC Report. More specifically, the Commission sought comments on the NERC Report's recommendations on areas in which CBM and TRM could be more specific and whether these recommendations go far enough in promoting a common CBM and TRM methodology within each region. The

[128] Supra note 9.

Commission also sought comments on the definitions of ATC, AFC, CBM and TRM. The Commission also solicited comments on the advisability of revising and standardizing ATC, AFC, TRM and CBM values. In addition, the Commission sought comments on the advisability of developing interconnection-wide standards for the Eastern Interconnection and WECC. Finally, the Commission asked for comments on the most expeditious way to obtain industry-wide standards for ATC calculations.

129. Furthermore, in the NOI, the Commission sought comments on whether undue discrimination is most likely to occur in areas such as ATC calculation where the transmission provider retains discretion as to how to implement a particular tariff provision.

Comments

Comments on Consistency

130. Many commenters express general support for some level of increased consistency in ATC calculations.[129] Some commenters urge the Commission to develop a consistent, industry-wide methodology for calculating ATC.[130] Constellation asserts that although transmission providers need to be innovative and flexible in many respects, a requirement

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[129] E.g., Alcoa, Ameren, AWEA, Calpine, Constellation, Cottonwood ATC NOI Comment, ELCON, Exelon, FTC ATC NOI Comment, Midwest ISO ATC NOI Comment, Midwest SATS, New York Commission ATC NOI Comment, North Carolina Commission, Occidental, South Carolina E&G, TAPS, and TransAlta.

[130] E.g., Alcoa, AWEA, Constellation, Exelon, Occidental, and Renewable Energy.

that all transmission providers use the same methodology to determine ATC would not only remedy the lack of clarity that surrounds these calculations and reservations, but would provide regulatory certainty and assist transmission customers in predicting the outcome of transmission service requests. This, in turn, Constellation suggests, would expand the commercial opportunities for transmission customers. According to Alcoa, AWEA and Renewable Energy, the industry-wide methodology should be a flow-based methodology, rather than a contract path methodology because they believe that a flow-based analysis provides a more realistic view of actual system usage and results in a more accurate assessment of ATC. Exelon further suggests that this uniform methodology should also apply to all transmission providers, including RTOs.

131. Other commenters argue against a one-size-fits-all approach, but rather express a preference for greater uniformity at a regional level to recognize regional differences. [131] These commenters suggest that due to differences in transmission systems or regions, it may not be practical or possible to standardize the ATC calculation methodology on an industry-wide basis. For example, Powerex cautions that nationwide standardization may not take into account the unique characteristics of particular systems or regions, such as the differences attributable to the West's contract-path model and the East's flow-based

[131] E.g., Alberta Intervenors, APPA, Bonneville, International Transmission, ISO/RTO Council, LDWP, MidAmerican, Nevada Companies, Powerex, Progress Energy, Public Generating Pool, Public Power Council, Salt River, Santa Clara, Snohomish, Tacoma Power, TANC, and TDU Systems.

model, as well as differences attributable to the primarily hydro-based systems in the Pacific Northwest.[132] Similarly, TANC argues that flowgate terminology and application in ATC calculation should not be required in the West because it does not adequately represent the nature of the many transmission constraints in the West. Other commenters caution that too much uniformity of the ATC calculation methodology could have an adverse effect on grid reliability.[133] In addition, some commenters urge the Commission not to adopt an ATC methodology that is so prescriptive that it inhibits new or better practices or imposes a wholesale revision of accepted market designs and processes that are working within established markets.[134]

132. Several commenters argue against any efforts to further standardize ATC calculations.[135] In its comments filed in the ATC NOI proceeding, LDWP asserts that the alleged problems with ATC are overstated. Moreover, it argues, the benefits of squeezing additional ATC from existing systems have not been established given that transmission customers can already request any capacity they need regardless of the posted ATC and transmission providers are required to make a good-faith effort to

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[132] Accord LDWP ATC NOI Comment, Public Power Council, Salt River, Snohomish, Tacoma, and TANC.

[133] E.g., NERC ATC NOI Comment, Public Power Council, and TVA.

[134] E.g., ISO/RTO ATC NOI Comment and Powerex.

[135] E.g., Cinergy, EEI, LG&E, LDWP ATC NOI Comment, National Grid, PPL, Public Generating Pool, San Diego G&E, Southern, TVA, and Xcel.

evaluate each request. Several commenters argue that the circumstances of individual transmission customers vary and often ATC calculations rely on the individual transmission provider's knowledge of its facilities and system conditions.[136] For example, Southern contends that too many factors go into the calculation of ATC to make the adoption of a static set of standards feasible. In fact, Southern and EEI maintain, standardization of ATC calculations is inconsistent with maintaining reliability because the circumstances of transmission providers vary significantly, and they must operate their systems based on their specific circumstances. In addition, LG&E maintains that standardizing ATC will not necessarily eliminate the need for TLR procedures to deal with load forecast errors and unplanned generation and transmission outages. Furthermore, some commenters argue that increased uniformity could impose significant costs upon utilities.[137]

133. Some commenters urge the Commission to increase the consistency of the elements of the ATC calculation, such as the kind of data inputs that transmission providers consider when evaluating ATC – including load levels, generator outage information, transmission outage information and generation dispatch information.[138] Exelon also urges the Commission to establish the assumptions that transmission

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[136] E.g., Southern and TVA.

[137] E.g., International Transmission and LG&E.

[138] E.g., Exelon and TDU Systems.

providers use in their ATC methodologies – such as how transmission reservations are accounted for and which reservations to model. Exelon also cites an example of modeling transaction counterflows, noting that uniform rules for data inputs are needed to ensure that transaction counterflows are modeled identically in both the planning and ATC/AFC calculation processes. In addition, commenters urge the Commission to establish the procedures for determining ATC (and its components) and to require a transmission provider to show that it has properly followed all required procedures.[139] Among other things, commenters suggest that the Commission should establish how frequently ATC is calculated, how frequently inputs are updated, require transmission providers to determine AFC instead of ATC, and require transmission providers to recognize all third-party flowgates that are requested to be monitored. In addition, several commenters state that the Commission should require that the methodology and inputs for ATC calculations be consistent with the transmission provider's planning or operating criteria.[140]

134. Several commenters urge the Commission to allow the industry, working through NERC and NAESB, to complete efforts already underway to further increase consistency

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[139] E.g., Ameren and Exelon.

[140] E.g., Exelon, ISO/RTO ATC NOI Comment, MISO, and NERC.

of ATC (and its components), as well as certain related business practices.[141] However, many of these commenters urge the Commission to give the industry, working through these organizations, specific guidance on what issues to decide and the parameters for the discussions.[142] Furthermore, commenters state that the Commission should establish a date certain for completion of these industry efforts,[143] and should also take an active role in the process.[144]

135. Other commenters suggest that the Commission should require that an independent entity develop and/or monitor a transmission provider's ATC methodology and its ATC calculations.[145] For example, Constellation states that it does not believe that the solution is to prohibit the transmission provider entirely from exercising its discretion, but instead to require transmission providers to retain an independent entity that can perform certain functions on a consistent, unbiased basis. In addition, the

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[141] E.g., Ameren, APPA ATC NOI Comment, Duke, EEI, Exelon, International Transmission Company ATC NOI Comment, ISO/RTO Council ATC NOI Comment, KCP&L, MidAmerican ATC NOI Comment, MISO ATC NOI Comment, Progress Energy, Southern, TAPS, TDU Systems, TransAlta, and WestConnect ATC NOI Comment.

[142] E.g., APPA ATC NOI Comment and International Transmission ATC NOI Comments.

[143] E.g., Duke and Exelon.

[144] E.g., APPA ATC NOI Comment, TAPS, and TransAlta.

[145] E.g., Arkansas Commission, Calpine, Constellation, EPSA, New York Commission, Occidental, and TDU Systems.

Arkansas Commission asserts that section 1281 of EPAct 2005[146] gives the Commission the authority to require the use of an independent coordinator of transmission to provide independent and verifiable transparency over critical Order No. 888 functions, such as ATC calculations.

136. Several commenters specifically address the lack of consistency in the industry on the definition and use of CBM and TRM. For example, TAPS notes that NERC does not require any transmission provider to reserve CBM. In addition, TAPS states, even in those regions that use CBM, there is often no regional methodology; it is up to the vertically integrated transmission provider to determine whether it wants to reserve CBM at all and at which interfaces, with no effective review of that determination. TAPS also states that TRM should be clearly defined and, if truly required for reliability, then all transmission providers should reserve it. According to TAPS, the Commission should define TRM in a manner that leaves no discretion as to whether, where, and how much capacity to set aside. EPSA also notes that there is a disconnect between the planning and expansion processes and the assumptions transmission providers use to calculate CBM and TRM.

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[146] EPAct 2005 sec. 1281(to be codified at section 220 of the FPA ,16 U.S.C. 824t), which concerns electricity market transparency rules.

137. TANC states that the Commission should closely examine the necessity of CBM in ATC calculations. Bonneville argues that there should only be one commercial margin instead of multiple margins (TRM, CBM, and others).

Comments on Data Exchange among Transmission Providers

138. Several commenters argue that the Commission should establish standards for resolving seams issues between transmission providers where each transmission provider uses a different methodology for calculating ATC.[147] Constellation and BC Transmission assert that when different transmission providers have different methods for determining ATC, this can lead to inefficiencies, including market confusion, lost sales/purchase opportunities, and unnecessary curtailments.

139. Commenters identify various elements of the ATC calculation methodology that they argue should be more consistent. For example, BC Transmission states that some of the elements that are calculated differently at the seams include the level of TRM, the level of CBM, the approach regarding the sale (or not) of TRM as non-firm capacity, assumptions regarding controlling interchange and assumptions regarding operating conditions. Similarly, MidAmerican in its response to the ATC NOI suggests that greater coordination is needed on partial path review, policies for decrementing AFC and redispatch policies. For example, MidAmerican references problems associated with

[147] E.g., BC Transmission, Constellation, Exelon, NY Transmission, Renewable Energy, and TDU Systems.

coordination between transmission providers on partial path treatment. Specifically, when transmission service involves a path across multiple systems, a given flowgate may be evaluated several times by various providers on the transmission path. Because of a lack of coordination between these providers, AFC on the flowgate may be decremented multiple times for the same transmission service request, and service may be denied even when the true available capacity on the flowgate is sufficient to allow the request to be granted. Exelon also states that certain data inputs must be coordinated across all transmission providers in an interconnection including load levels, transmission outages, generation outages and generation dispatch. In addition, Exelon states, the Commission should establish how transmission providers account for transmission reservations in an ATC/AFC calculation.

140. Moreover, NY Commission suggests that this problem goes beyond the non-independent transmission providers. According to NY Commission, in order for RTOs to properly determine tie flow limits, they need access to certain information from the control region on the other side such as load levels and distributions, generator dynamic capability and expected outputs, phase shifter positions and standard contingencies required by that control area. In addition, NY Commission states, these inputs need to be updated daily.

141. Finally, Alcoa states that the potential for underestimating ATC is likely another consequence of the fundamental conflict between the contract path model and the electricity path model of contracting for electric energy. According to Alcoa, outside of

ISO/RTO systems, utilities may not have enough data available to compute ATC, since they may not be able to accurately complete all relevant parallel path transactions.

Comments on Transparency

142. Commenters are overwhelmingly in favor of greater transparency in the ATC calculation methodology to provide more assurance that a transmission provider is not performing its ATC calculations in an inconsistent or unduly discriminatory manner.[148] EEI suggests that transmission providers could make their base case load flow studies on which they base their calculation of ATC available to transmission customers, subject to security and confidentiality protections. Other commenters state that greater transparency could be achieved through the imposition of additional posting requirements on OASIS.[149] These commenters argue that the Commission should require transmission providers to post their discrete methodologies and algorithms for evaluating ATC, as well as their transmission modeling information and their various assumptions. Commenters further suggest that transmission providers should be required to provide information

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[148] E.g., Alcoa, Ameren, APPA, Calpine, CEOB, Cinergy, Constellation, Cottonwood, Duke, EEI, ELCON, HQ Energy, LDWP, MidAmerican, Midwest ISO, Midwest SATs, Powerex, PPL, Progress Energy, Public Generating Pool, Public Power Council, Salt River, Southern, TANC, TAPS, TDU Systems, TransAlta, and TVA.

[149] E.g., Calpine and PPL.

regarding planned outages, and to ensure consistent treatment of outage information between control areas.[150]

143. In its reply comments, Southern acknowledges that greater transparency would reduce concerns of undue discrimination, but cautions the Commission against imposing unnecessary and duplicative posting requirements and notes that much of the information that commenters have asked the Commission to make transparent is in fact already publicly available through a variety of sources.

144. In addition, some commenters urge the Commission to impose meaningful reporting requirements.[151] In this regard, Constellation asserts that the Commission should modify the pro forma OATT to require that transmission providers post systematic, timely and accurate reporting of certain service metrics such as transaction requests approved, rejected, confirmed, and curtailed. Similarly, Cottonwood states that transmission providers should be required to provide information detailing why a particular transmission request was denied and whether there are other available alternatives. In addition, several commenters argue that transmission providers also should be required to post their relevant business practices, operating standards, protocols and internal guidelines that affect transmission service.[152] TDU Systems also urge the

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[150] E.g., H.Q. Energy and Powerex.

[151] E.g., Constellation, Cottonwood, and TDU Systems.

[152] E.g., Powerex and TransAlta.

Commission to require transmission providers to explain why transactions are allowed to flow even when the posted ATC value was zero.

145. EPSA argues that capacity is unnecessarily held from the market when transmission providers reserve excessive amounts for their native load and when they fail to make capacity available through redispatch. EPSA states, however, that there is no way of knowing whether there is a hoarding problem because there is no requirement to post the necessary real time information on transmission utilization, and recommends a requirement to post such information. Powerex contends there is an incentive for transmission providers to hoard because grandfathered or other firm rights held by the transmission provider to serve native load are subsequently used for wholesale marketing purposes. It further states, however, that evidence of anticompetitive practices is difficult to obtain because of a lack of transparency. Powerex supports increased requirements for both uniform and transparent ATC calculation.

146. Several commenters urge the Commission to establish compliance review procedures and impose sanctions for violations to ensure that transmission providers are accountable for ensuring that their ATC calculations are correct.[153] In its response to the ATC NOI, Cottonwood states that the Commission should develop specific tests (benchmarks) to monitor transmission providers' performance. In addition, HQ Energy

[153] E.g., Cottonwood ATC NOI Comment, ELCON, HQ Energy, NRECA, Occidental, and Powerex.

states that the Commission should conduct periodic reviews of whether non-independent transmission providers have properly calculated and allocated ATC. ELCON states that the Commission should place the burden of proof to depart from its ATC methodology on the transmission provider and include specific penalties in the tariff for transmission providers that are found to be in violation.

147. HQ Energy and Powerex also state that the Commission should require transmission providers to ensure that staff is available at all times to respond to customer inquiries regarding real-time transactions.

Discussion

148. We propose to address the potential for remaining undue discrimination in the determination of ATC by requiring industry-wide consistency and transparency of certain definitions, data, modeling assumptions and components of ATC. We propose to provide general guidance regarding the aspects of ATC calculation that we believe should be more consistent and direct public utilities, working through NERC and NAESB, to use our guidance to revise the relevant standards and business practices. In addition, we propose to require increased detail in the pro forma OATT regarding the method of calculating ATC and to amend our OASIS regulations to require increased transparency.

149. Though NERC and NAESB currently are working on certain proposals to address the problems we have identified,[154] we are concerned that without guidance, direction and a firm deadline, these industry developments may not succeed due to other conflicting priorities. We believe that the existing NERC and NAESB processes are well-suited to achieving greater consistency in ATC calculations. It is our expectation that NERC and NAESB will expand on the work they have already undertaken to achieve the goals we propose to set out for them.

150. We propose to take this action pursuant to our obligation under FPA section 206 to remedy undue discrimination in the provision of transmission service. Transmission providers in general enjoy substantial discretion in establishing and interpreting the specific algorithms, data, and assumptions needed to assess ATC. Though we do not believe it is possible or necessary to entirely eliminate discretion, unchecked discretion affords a transmission provider the ability and opportunity to discriminate in its favor (and its affiliate's favor) against third parties in how it calculates and allocates ATC and, therefore, may be unjust, unreasonable, unduly discriminatory and preferential. Transmission providers have an incentive to understate ATC on transmission paths that

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[154] We understand that two NERC standard authorization requests related to ATC/TTC/AFC and CBM/TRM were approved earlier this year, and that drafting of the standards' revision is underway. We further understand that NAESB has a concurrent drafting effort underway for associated business practices that will follow a coordinated path with the NERC process. See http://www.nerc.com/~filez/standards/MOD-V0-Revision.html.

would be valuable to power sellers that are competitors to the transmission providers' own (or their affiliates') power sales. Where transmission congestion exists, the methodology for calculating ATC will effectively determine whether competitors have access to the transmission grid, and the lack of any consistent methodology for calculating ATC gives transmission providers excessive discretion in making this determination.

151. The lack of consistency and detail in the determination of ATC can facilitate undue discrimination in a variety of ways. Transmission providers may use generation dispatch assumptions that result in limited capacity being available to merchant generators. They also may use different inputs and assumptions for purposes of calculating ATC for third parties than they do for system planning for retail native load. As noted above, a transmission provider could reduce a facility rating or model certain facilities as out of service, which would have the effect of underestimating TTC. In determining ETC, transmission providers have discretion to determine the capacity needed and set aside for native load usage. Each of these exercises of discretion has a significant effect on ATC.

152. The lack of transparency into how a transmission provider calculates and allocates its ATC (including all assumptions and data inputs) makes it difficult to detect discriminatory behavior. This lack of transparency frustrates and increases the costs of compliance and enforcement efforts. Many transmission providers have urged the

Commission to provide greater clarity in the rules for OATT service,[155] particularly given the threat of the Commission's new civil penalty authority.

153. In addition to our preliminary finding that the lack of consistent, industry-wide ATC calculation standards is unjust and unreasonable under FPA section 206, we believe that it poses a threat to the reliable operation of the bulk-power system. A transmission provider needs to know how much electricity its system can carry. The lack of a consistent, industry-wide methodology for evaluating ATC and the lack of data sharing among transmission providers often leads to problems in determining the appropriate ATC value. Despite a transmission provider's good faith attempt to calculate and post accurate ATC levels, it can find that transmission that it thought was available on its system no longer exists because it was unaware of decisions by other transmission providers. This, in turn, can threaten the reliable operation of the interconnected transmission system.[156]

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[155] E.g., Ameren, APPA ATC NOI Comments, Duke, EEI, Exelon, International Transmission Company ATC NOI Comments, ISO/RTO Council ATC NOI Comments, KCP&L, MidAmerican ATC NOI Comments, MISO ATC NOI Comments, Progress Energy, Southern, TAPS, TDU Systems, TransAlta, and WestConnect ATC NOI Comments.

[156] According to NERC, "the lack of standardization and more significantly, limited coordination can negatively impact both the market, through the need for a large number of [TLR] actions (or curtailments in WECC) and, on occasion, reliability when even the use of TLRs provides insufficient relief on some critical interfaces." See NERC Report at 1.

154. As a result of reliability effects of inconsistent ATC calculations, our proposal for greater consistency and transparency also is supported by our new authority under section 215 of the FPA, which gives the Commission jurisdiction to certify an Electric Reliability Organization (ERO) and to approve reliability standards that are just, reasonable, not unduly discriminatory or preferential, and in the public interest. The Commission also has authority to order the ERO to submit a reliability standard that the Commission considers appropriate to implement FPA section 215.[157] On April 4, 2006, NERC submitted an application to be certified as the ERO, as well as proposed reliability standards.[158] In this NOPR, we direct our guidance to public utilities and recommend that they implement our direction by working with NERC. However, this is not intended to prejudge the outcome of the ERO proceeding. Though the Commission will act independently on the reliability standards proposed by NERC in Docket No. RM06-16-000, we believe it is prudent to provide our guidance now on NERC's reliability standards related to ATC by providing specific direction on what should be more consistent and a timeframe for completion of NERC's efforts.[159] As we indicated above, the lack of consistency, data exchange and transparency in ATC calculations not only can

[157] Section 215(d)(5).

[158] See Docket Nos. RR06-1-000 and RM06-16-000.

[159] In this NOPR, we direct our guidance to NERC, though the reliability standards relating to ATC ultimately will be adopted by the ERO.

increase the opportunities for undue discrimination but also can threaten reliability. We therefore believe that Commission action pursuant to FPA section 215 may be appropriate on reliability standards related to ATC calculation. Any action on these reliability standards that is taken in Docket No. RM06-16-000 (the ERO standards rulemaking) will be coordinated and consistent with our determinations regarding ATC calculation in this proceeding.[160]

Consistency

155. The Commission proposes to require public utilities, working through NERC, to develop the standards we set forth below within 6 months of the final rule in this proceeding. Consistent with NERC's existing efforts, we propose to require the development of standards for: (1) ATC/AFC, TTC/Total Flowgate Capacity (TFC), ETC, CBM, and TRM calculation methodologies, (2) data inputs, (3) modeling assumptions, (4) ATC calculation frequency, and (5) data exchange and coordination processes. We further propose to require public utilities, working through NAESB, to work with NERC to identify the appropriate business practices to complement the standards developed by NERC. We discuss below each of the elements for which we propose to require more consistency. We seek comment on these elements of the ATC

[160] We note that Commission staff recently released a preliminary assessment of the proposed ATC-related reliability standards, stating that they "may result in unnecessary regional variations not justified by technical differences and inconsistent applications." Staff Preliminary Assessment of the North American Reliability Council's Proposed Mandatory Reliability Standards at 80 (May 11, 2006).

calculation and, in particular, whether certain elements are more susceptible to further consistency than others and whether certain elements should be prioritized over others because they represent the source of most disputes between transmission providers and customers. We recognize the need to focus on those elements of the ATC calculation that are most susceptible to further consistency and most important in terms of eliminating opportunities for undue discrimination.

156. The Commission recognizes that transmission providers use several basic types of ATC calculation methodologies (with various permutations), and does not believe that a single ATC calculation methodology must be applied by all transmission providers.[161] However, we agree with commenters who argue that the amount of discretion in the existing ATC calculation methodologies gives transmission providers the ability and opportunity to unduly discriminate against third parties. Accordingly, we propose to achieve greater consistency in ATC calculations by directing the development of consistent definitions of the components of ATC, as well as consistent data inputs, data exchange and coordination protocols, and modeling assumptions, as discussed further below. We believe that this level of consistency will go a long way toward producing

[161] For example, there are two primary ATC calculation methodologies: the contract path approach and the flowgate approach. See generally P 115. However, the ATC values that result from application of either method should largely be the same if consistent data inputs and modeling assumptions are used.

more coherent and uniform determinations of ATC across a region, thereby helping to eliminate the potential for undue discrimination.[162]

157. We propose to direct public utilities, working through NERC, to develop consistent practices for TTC/TFC calculation methodologies. We recognize that the NERC reliability regions have historically calculated transfer capability using different approaches.[163] However, we expect that guidelines can be developed for the calculation of transfer capability that use a common approach to model power transfers. In addition, we believe that the criteria used for identifying flowgates and determining TTC/TFC can be more consistent.

158. The Commission believes that the lack of consistency of ETC permits too much discretion in determining how much capacity a transmission provider sets aside for native load, including its network customers. We believe that the development of an industry-wide methodology can limit this discretion. Therefore, we propose to require the development of a consistent methodology for determining the capacity needed and set aside for native load usage. In addition, we propose that accounting for transmission reservations in an ATC/AFC calculation also should be more consistent. Presently, there

[162] As discussed further below, for consistency to be fully effective, it should be coupled with increased transparency. As such, we also propose greater transparency below.

[163] One approach models power transfers by scaling up/down the load, a second approach scales generation up/down, and yet another approach uses a combination of changes in load and generation.

are two main methods in use. One method models all "appropriate reservations"[164] in the power flow base case model. The other method models only those reservations that are expected to be actually scheduled and accounts for others by decrementing flowgate AFC. It is important for consistency to use the same calculation technique when modeling these types of reservations. Therefore, we propose that public utilities, working through NERC, establish and specifically identify which reservations they use in determining ETC.

159. The Commission has previously addressed the lack of a consistent industry-wide methodology for determining CBM. Following a two-day technical conference, the Commission held in the CBM Order[165] that transmission providers continue to wield significant latitude in interpreting how CBM is determined. The Commission directed that the CBM set-aside be more transparent, more accurate, and more widely available.[166] We remain concerned, however, that transmission providers have preferential access to the interface capacity that is set aside. This interface capacity is paid for by all transmission customers whether or not they receive a benefit from the set-aside. In

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[164] "Appropriate reservations" takes into account the time frame (e.g., yearly, monthly) and ATC product (e.g., firm, non-firm) being calculated.

[165] Capacity Benefit Margin in Computing Available Transmission Capacity, 88 FERC ¶ 61,099 (1999) (CBM Order).

[166] CBM Order at 61,237-38.

general, we believe that the latitude associated with CBM undermines the certainty and transparency that is needed for non-discriminatory, open-access transmission service.

160. The current pro forma OATT offers two means of reserving transfer capability, either of which implicitly provides some financial discipline to overreservations. The first is the requirement to designate a network resource on the other side of the interface and assume the associated financial responsibility of either owning the resource or executing a firm power purchase agreement. The other is to contract for firm point-to-point service on the interface, which requires the payment of a point-to-point reservation charge. In either case there is a disincentive to reserving transfer capability simply to prevent someone else from using it on a firm basis. With these processes in mind, the Commission has identified three possible options to provide the necessary certainty, transparency, and financial discipline necessary to remedy the potential for undue discrimination associated with inappropriate ATC set-asides for CBM. These options need not be mutually exclusive.

161. One option is to require that clear standards be developed for how the CBM value should be determined and allocated across transmission paths, and for which customers CBM should be used.[167] Consistent with the standards development process that is already in progress, we propose that these standards specify how CBM should be

[167] NERC has already contemplated developing a standard to address CBM issues. See http://www.nerc.com/~filez/standards/MOD-V0-Revision.html.

reserved to allow any load-serving entity to meet generation reliability criteria on a nondiscriminatory basis. In addition, we propose that NERC specify emergency generation deficiency conditions during which a load-serving entity will be allowed to use the transfer capability reserved as CBM. We believe that CBM should be reserved only when there is insufficient local generation capacity to meet generation reliability standards, and it should always have a zero value in the calculation of non-firm ATC.

162. Another approach may be to develop a specific charge for setting aside ATC for CBM. This approach would treat CBM as a service that would be available to customers serving load within the transmission provider's service area. To do this, the Commission would propose that an entity for which transfer capability has been set aside to meet generation reliability criteria be charged a separate rate for this service. We seek comment on this proposal to charge a separate rate, as well as comment on the potential impacts on overall rates and revenues. We also seek comment on whether there are credible situations in which the proposal would not be feasible. Commenters are encouraged to provide specific examples.

163. A third option may be to eliminate CBM and replace it with specific transfer capability reservations associated with designated network resources. In several cases, the Commission addressed instances when transmission providers had taken advantage of their ability to preserve interface capability to serve their own load while limiting the ability of competing suppliers to access customers on their systems. In these orders, the Commission position was that if a utility wanted to use firm transmission capacity on an

interface to serve its native load, it was required to designate a network resource associated with that capacity on the other side of the interface pursuant to the requirements of the pro forma OATT.[168] Specifically, the Commission stated that the pro forma OATT requires the transmission provider to designate all network resources, including those acquired for the purpose of meeting generation reserves, in the same manner as network customers do.[169] The retention of this obligation would require the transmission provider to replace any existing set-aside of firm transfer capability as CBM with reservations for specific designated resources. We seek comment on the reasonableness of eliminating CBM and any impacts on the reliable operation of the transmission system. Commenters are encouraged to provide specific examples of transmission providers that currently do not use CBM and, alternatively, conditions under which CBM must be used. We also ask for comments on how eliminating CBM would affect the ability of load-serving entities to meet existing generation reliability adequacy requirements.

164. The Commission proposes that public utilities, working through NERC, develop clear standards for how TRM is determined, allocated across transmission paths, and

[168] See Aquila supra note 121; see also Morgan Stanley Capital Group v. Illinois Power Co., 83 FERC ¶ 61,204, clarified, 83 FERC ¶ 61,299 (1998), order on reh'g, 93 FERC ¶ 61,081 (2000).

[169] Wisconsin Public Power Inc. SYSTEM v. Wisconsin Public Service Corp., 83 FERC ¶ 61,198 at 61,857-58 (1998).

used. In addition, we propose to require that the standards ensure that there will be no contingency double-counting when calculating TRM, TTC and CBM. We also propose that the standards developed should specify the uncertainties that are accounted for in TRM and the methods used to determine their impacts on TRM values. The Commission proposes that TRM can be used to accommodate uncertainties such as: (1) load forecast and load distribution error, (2) variations in facility loadings, (3) uncertainty in transmission system topology, (4) loop flow impact, (5) variations in generation dispatch, including intermittent resources, (6) automatic sharing of reserves, and (7) other uncertainties identified through the NERC forums.

165. The Commission acknowledges that accurate data and system models are essential to accurately simulate the performance of the electric system when calculating ATC. The data and models used by the transmission provider should be consistent, to the maximum extent practicable, with the data and models used for the planning, operation, and expansion of the transmission system. While NERC's current ATC-related standards (MOD-001- MOD-009) require that steady state and dynamic data be submitted and that steady state and dynamic system models be prepared, there is no requirement to periodically benchmark these models and appropriately modify them against actual

system events.[170] Therefore, the Commission proposes that public utilities, working through NERC, modify the ATC-related standards to incorporate a requirement for the periodic review and modification of these models (including load flow base cases, short circuit data, transient and dynamic stability simulation data, contingency,[171] subsystem and monitoring files, and production cost models), in order to ensure that they are up to date.

166. Modeling assumptions are a crucial element in the calculation of ATC. The Commission proposes that public utilities, working through NERC, develop consistent assumptions for use in ATC determinations. The Commission proposes that the assumptions used in the calculation of ATC be made consistent among transmission providers, to the maximum extent practicable. In general, the Commission believes that the assumptions used in the determination of ATC should be consistent with those used when planning the operation and expansion of the transmission system. This is necessary to remedy the potential for undue discrimination between the manner in which a transmission provider plans and operates its system to serve native load and the manner in which it calculates ATC for service to third parties. Consequently, the models for

[170] See U.S.-Canada Power System Outage Task Force, Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations, Recommendation Number 24 (April 2004). See https://reports.energy.gov/.

[171] Contingency files should contain information on special protection schemes and remedial action plans.

short- and long-term ATC calculation should be developed using consistent assumptions regarding the load level, generation dispatch, transmission and generation facilities maintenance schedules, contingency outages and topology as those used in the planning for operation and expansion. In addition, the long-term ATC models should rely to the maximum extent practicable upon the same assumptions regarding new transmission and generation facilities additions and retirements as those used in the planning for expansion.

167. More specifically, the Commission proposes to direct public utilities, working through NERC, to establish consistent assumptions that are related to the modeling of: (1) representative load levels, (2) generation dispatch, (3) transmission reservations and (4) counterflows, in addition to any other modeling assumptions identified by NERC. Regarding the assumptions used for load level modeling in the ATC calculation, the Commission proposes to require all transmission providers to have a consistent approach to modeling of load levels. With respect to the base generation dispatch, we propose that public utilities, working through NERC, establish a method for determining which generators should be modeled in service, including guidance on how independent generation should be considered. With respect to modeling of particular transactions, the Commission believes that a consistent approach is needed on how to simulate power flows from points of receipt to points of delivery when sources are unknown. Accounting for transmission reservations in an ATC/AFC calculation also should be

consistent.[172] We note that the purpose of more consistent modeling assumptions is to eliminate discretion and the potential for undue discrimination. This proposal is not intended to change the manner in which native load customers are served. We seek comment on whether (and, if so, how) this proposal would affect service to native load customers.

168. The Commission also supports the development of clear standards on how often ATC/AFC and its individual components are calculated and updated. The Commission proposes that public utilities, working through NERC and NAESB, develop standards requiring that the calculation be performed on a consistent time interval among transmission providers and in a manner that closely reflects the actual topology of the system concerning generation and transmission outages, load forecast, interchange schedules, transmission reservations, facility ratings, and other necessary data. The Commission also supports uniform updating of ATC values and components by adjacent control areas.

169. The Commission believes that significant improvements in the communication, coordination, and exchange of data across all transmission providers in an interconnection are needed to produce accurate determinations of ATC. Therefore, we propose that public utilities, working through NERC, develop consistent protocols that

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[172] Currently, one method models all appropriate reservations in the power flow base case model, when another models only those reservations that are expected to be scheduled, and accounts for others by decrementing flowgate AFC.

would enable and require the exchange of data among transmission providers. We propose that the following data, at a minimum, should be exchanged among transmission providers for the purposes of ATC modeling: (1) load levels, (2) transmission planned and contingency outages, (3) generation planned and contingency outages, (4) base generation dispatch, (5) existing transmission reservations, including counterflows, (6) ATC calculation frequency, and (7) source / sink modeling identification. In addition, NERC may identify other data needs through the standards development process. We seek comment as to how much data sharing is workable; whether there are additional data that should be provided; whether access to such data should be limited to transmission providers; and if there are existing forums by which these or similar data are already shared.

170. In order to facilitate the process for achieving consistency in ATC calculations we have proposed in this NOPR, the Commission directs Staff to hold a technical conference. The technical conference will be transcribed to provide the Commission and NERC a record of the comments received at the conference. The Commission will provide further guidance regarding the date of the technical conference and the topics it intends to address at the technical conference in a subsequent notice.

Transparency

***Pro forma* OATT**

171. Though the Commission's requirement that a transmission provider describe its ATC calculation methodology in its OATT has not changed, that requirement has been

interpreted in various ways. Some transmission providers post a detailed explanation of how they calculate ATC, while other transmission providers post very general descriptions that fail to offer sufficient detail for third parties to understand how ATC has been derived. The Commission is concerned that the lack of transparency in some of the descriptions provided by transmission providers gives these transmission providers too much discretion to change ATC practices without sufficient oversight and review. The Commission also is concerned that this lack of transparency could allow transmission providers to unduly discriminate against their competitors when allocating transmission service. We agree with commenters that greater transparency is needed into how transmission providers calculate and allocate ATC. Accordingly, in order to ensure that transmission service is provided in a nondiscriminatory manner, we propose to require transmission providers to take certain measures to make their ATC calculation process more transparent. We believe that these proposed changes will give transmission customers access to sufficient information to be able to examine the integrity of the process. Moreover, our proposal for greater consistency in the way ATC is calculated should aid in transparency because there will be far fewer differences in the way individual transmission providers calculate ATC. This will make it less difficult to determine whether ATC is being calculated in an unduly discriminatory manner.

172. Specifically, we propose to require transmission providers to include, at a minimum, in Attachment C of their OATT, the following information concerning their ATC calculation methodology (including the calculation of AFC, if applicable). First, we

propose to require transmission providers to state their specific mathematical algorithm used to calculate their firm and non-firm ATC (and AFC, if applicable) for their scheduling horizon (same day and real-time), operating horizon (day ahead and pre-schedule) and their planning horizon (beyond the operating horizon). Second, we propose that transmission providers provide a process flow diagram that illustrates the various steps through which the ATC/AFC is calculated.

173. In addition, we propose to require transmission providers to include in Attachment C a detailed explanation of how each of the ATC components is calculated for both the operating and planning horizons. Thus, for TTC, a transmission provider should: (1) explain its definition of TTC; (2) explain its TTC calculation methodology (e.g., load flow, short circuit, stability, transfer studies); (3) list the databases used in its TTC assessments; and (4) explain the assumptions used in its TTC assessments regarding load levels, generation dispatch, and modeling of planned and contingency outages.

174. For ETC, we propose to require a transmission provider to explain: (1) its definition of ETC; (2) the calculation methodology used to determine the transmission capacity to be set aside for native load and non-OATT customers; (3) how point-to-point service requests are incorporated; (4) how rollover rights are accounted for; and (5) its processes for ensuring that non-firm capacity is released properly (e.g., when real time schedules replace the associated transmission service requests in its real-time calculations). With regard to (5), we seek comment on whether transmission providers

currently are keeping track of when firm service reservations are not scheduled and should be released as non-firm.

175. If a transmission provider uses an AFC methodology to calculate ATC, we propose to require it to explain: (1) its definition of AFC; (2) its AFC calculation methodology (e.g., load flow, short circuit, stability, transfer studies); (3) its process for converting AFC into ATC; (4) what databases are used in its AFC assessments; (5) the assumptions used in its AFC assessments; and (6) the reliability criteria used for contingency outages simulation.

176. For TRM, we propose to require a transmission provider to explain: (1) its definition of TRM; (2) its TRM calculation methodology (e.g., its assumptions on load forecast errors, forecast errors in system topology or distribution factors and loop flow sources); (3) the databases used in its TRM assessments; (4) the conditions under which the transmission provider uses TRM; and (5) the process used to prevent double-counting of contingency outages used in its TTC and TRM calculations. We propose to require transmission providers that do not reserve TRM to reflect that in Attachment C. We seek comment on the above proposal, specifically on what type of showing a transmission provider could make with regard to the process used to prevent double-counting.

177. Furthermore, in the CBM Order, the Commission required transmission providers to post a specific and self-contained narrative explanation of their CBM practices, including who performs the assessment (transmission or merchant staff), the methodology used to perform generation reliability assessments (e.g., probabilistic or

deterministic), whether the assessment method reflects a specific regional practice, the assumptions used in those assessments and the basis for the selection of paths on which CBM is set aside. In addition, the Commission directed transmission providers to post their procedures for allowing CBM during emergencies (with an explanation of what constitutes an emergency, the entities that are permitted to use CBM during emergencies and the procedures which must be followed by the transmission providers' merchant function and other load-serving entities when they need to access CBM). The Commission further stated that if a utility's practice was not to reserve CBM, it should reflect that in Attachment C. We propose to require transmission providers to include this narrative in Attachment C of their OATTs.

178. In addition, for CBM, we propose to require a transmission provider to: (1) explain its definition of CBM; (2) list the databases used in its CBM calculations; and (3) prove that there is no double-counting of contingency outages when performing CBM calculations.

179. Though we are proposing to require transmission providers to provide greater clarity in the description of their ATC calculations, it is our expectation that the reforms we propose for greater consistency of ATC methods will minimize the burden on transmission providers and customers of assessing various ATC calculation methodologies. Ultimately, when the ATC standards development process we propose is completed, we expect that Attachment C will refer to the NERC standards and will differ

by transmission provider only with respect to the limited elements of the ATC calculation that may not have been made consistent.

OASIS

180. The Commission's existing regulations require certain ATC-related information to be posted on each transmission provider's OASIS, while other information is required to be provided on request. To ensure that relevant information is available on a timely basis to all market participants, we propose to amend our regulations to allow potential customers greater access to information that will enable them to obtain service on a non-discriminatory basis from any transmission provider.[173] We believe that our proposed reforms will not only enhance the amount and accuracy of information available to customers, but will also increase the ability of the Commission and others to detect any potentially unduly discriminatory behavior in a transmission provider's calculation and allocation of ATC.

181. Our regulations state that a transmission provider's[174] ATC and TTC calculations shall be performed according to consistently applied methodologies referenced in the transmission provider's OATT and shall be based on current industry practices, standards

[173] See 18 CFR 37.2 (2005).

[174] We note that various provisions of the OASIS regulations use the term "Responsible Party," which means the transmission provider or an agent to whom the transmission provider has delegated the responsibility of meeting any of the requirements of the regulations. For simplicity, however, we will use the term "transmission provider" here.

and criteria.[175] We propose to revise this provision to include compliance with the reliability standards developed by the ERO – i.e., ATC and TTC calculations shall be performed according to consistently applied methodologies referenced in the transmission provider's OATT and shall be based on the ERO reliability standards as well as current industry practices, standards and criteria.

182. The regulations further state that, on request, a transmission provider must provide all data used to calculate ATC and TTC for any constrained paths.[176] Transmission providers also are required to make any system planning studies or specific network impact studies performed for customers to determine network impacts publicly available on request and to post a list of such studies on the OASIS.[177] The Commission proposes to maintain these requirements.

183. The Commission's OASIS regulations require transmission providers to calculate and post ATC and TTC for each posted path.[178] The regulations define two classes of posted paths based on usage: "constrained" and "unconstrained." A constrained posted path is any posted path for which ATC has been less than or equal to 25 percent of TTC at any time during the preceding 168 hours or is calculated to be less than, or equal to,

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[175] See 18 CFR 37.6(b)(2)(i) (2005).

[176] See 18 CFR 37.6(b)(2)(ii) (2005).

[177] See 18 CFR 37.6(b)(2)(iii) (2005).

[178] See 18 CFR 37.6 (2005).

25 percent of TTC for any period during the current hour or the next 7 days. An unconstrained posted path is any posted path that is not a constrained posted path.[179] The Commission proposes to amend the regulations relating to the data posted for constrained posted paths, but largely to retain the existing posting requirements for unconstrained posted paths, as set forth below.

184. First, in the CBM Order, the Commission required transmission providers, with respect to each path for which the utility already posts ATC, to post (and update) the CBM figure for that path. The Commission also required transmission providers to make any transfer capability set aside for CBM available on a non-firm basis and to post this availability on OASIS. The Commission proposes to incorporate these CBM posting requirements into its regulations.

185. With respect to paths for which the utility already posts ATC, TTC, and CBM, we further propose to require each transmission provider to also post (and update) the TRM value for that path.

186. Our existing regulations require ATC and TTC on constrained paths to be updated when: (1) transactions are reserved, (2) service ends, or (3) whenever the TTC estimate for the path changes by more than 10 percent. We do not believe that this regulation has

[179] See 18 CFR 37.6(b)(1)(iii(2005). Our regulations require transmission providers to post ATC and TTC for specific time horizons for constrained posted paths and unconstrained posted paths. The Commission proposes to maintain the existing time horizons. See 18 CFR 37.6(b)(3)(i)-(ii) (2005).

resulted in sufficient information to determine why ATC values changed. To provide a transmission customer with useful information to assist with its evaluation of monthly and yearly firm transmission service options, we propose to supplement the existing regulations by requiring the transmission provider to post a brief, but specific, narrative explanation of the reason for the posted change in the monthly and yearly ATC values on a constrained path. This narrative would describe, for example: (1) scheduling of planned outages and occurrence of forced transmission outages; (2) de-ratings of transmission facilities; (3) scheduling of planned generation outages and occurrence of forced generation outages; (4) changes in load forecast, (5) changes in new facilities in-service dates, or other events or assumption changes that cause the ATC value to change. We seek comment on whether the posting of this new information would provide adequate transparency to the customer on a frequent enough basis without imposing an undue burden on the transmission provider. We seek comment on whether a similar narrative also should be required when ATC remains unchanged at a value of zero for some specified period of time.

187. We propose to maintain the requirement in 18 CFR § 37.6(e)(2)(i) that a transmission provider must post the reason for a denial of a request for service. We propose, however, to amend this provision to require a transmission provider to maintain and make available information supporting the reason for the denial for five years. In addition, we propose to extend the time period for which transmission providers must maintain transmission service information for audit. Our regulations currently require

audit data to be retained and made available upon request for download for three years from the date when they are first posted.[180] We propose to change the period from three to five years.

188. In the CBM Order, the Commission stated that the level of ATC set aside for CBM can and should be reevaluated periodically to take into account more certain information (such as assumptions that may not have, in fact, materialized). Thus, the Commission directed transmission providers to periodically reevaluate their generation reliability needs so as to make known the availability of CBM and to post on OASIS their practices in this regard. We propose to incorporate these requirements in the Commission's regulations and to obligate transmission providers to reevaluate the CBM set aside at least quarterly.

189. We also propose to require the transmission provider and network customers to use the transmission provider's OASIS to request designation of a new network resource and to terminate the designation of a network resource. As with other transmission request information posted on OASIS, the transmission provider should keep designation and termination information posted on OASIS for 90 days and should make designation and termination information available upon request for five years, consistent with 18 CFR 37.7(b) (2005). Transmission customers will be able to query requests to designate and terminate a network resource under 18 CFR 37.6(a)(6)(2005). We propose to require

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[180] See 18 CFR 37.7(b) (2005).

the transmission provider to post on its OASIS a list of its current designated network resources and all network customers' current designated network resources. The list of network resources should include the name of the resource, its geographic and electrical location, and the amount of capacity from the unit to be designated as a network resource.

190. Finally, we remind transmission providers that transfer capability associated with transmission reservations that are not scheduled in real time must be included in non-firm ATC and posted on OASIS.[181]

CEII

191. Shortly after the attacks on September 11, 2001, the Commission removed from public viewing certain documents that were likely to contain detailed specifications of critical infrastructure facilities. CEII is information concerning proposed or existing critical infrastructure (physical or virtual) that: (1) relates to the production, generation, transportation, transmission, or distribution of energy; (2) could be useful to a person in planning an attack on critical infrastructure; (3) is exempt from mandatory disclosure under the Freedom of Information Act, 5 U.S.C. § 552 (2000); and (4) does not simply give the location of the critical infrastructure. Accordingly, access to transmission-related information collected by the Commission has been restricted by the Commission's CEII regulations. Thus, for example, information filed in FERC Form

[181] Our regulations require non-firm ATC and TTC for constrained posted paths to be posted in the same manner as firm ATC and TTC, except that monthly and seasonal capability need only be posted if requested. See 18 CFR 37.6(b)(3)(i)(B)(2005).

No. 715 (including base case power flow data and transmission system maps) as well as system planning and network impact studies and models are no longer publicly available. However, requesters with a particular need (such as transmission customers and consultants with legitimate needs) have the opportunity to access information designated as CEII from the Commission by submitting a request to the Commission under the procedures set forth in our regulations. In Order No. 643,[182] the Commission addressed situations in which its regulations require public utilities to disclose information directly to the public. The Commission ruled that potential CEII disclosed directly from the public utility to the public should be evaluated under the same rules addressing the disclosure of CEII from the Commission to the public, i.e., if an entity concludes that certain of its information is CEII, it must designate it as such and provide other specified information about obtaining access to the CEII through the Commission's process. The Commission also held that it did not intend to restrict an entity's ability to reach appropriate arrangements for sharing CEII, and that all persons with a legitimate need for CEII should be able to gain access to it with a minimum of difficulty.[183]

192. We believe that much of the information we propose to require transmission providers to provide in this proposed rulemaking will not pose CEII concerns. If

[182] Amendments to Conform Regulations with Order No. 630, Order No. 643, 68 FR 52089 (Sep. 2, 2003), FERC Stats. & Regs. ¶ 31,149 (2003).

[183] Id. at P 16.

commenters believe that any of the information is CEII, they should explain the basis for that view. We recognize that requiring interested persons to use the existing CEII process to access information we propose to require transmission providers to provide in this rulemaking could undermine our goal of providing increased transparency to information necessary to evaluate the use of the transmission system. As a result, we seek comment on procedures that could be adopted by transmission providers to streamline the resolution of CEII concerns and allow timely disclosure of information from the transmission providers to interested persons.

Additional Data Posting

193. Notwithstanding our proposed reforms requiring greater consistency of and increased transparency into ATC calculation methodologies, certain aspects of ATC calculation may remain committed to the discretion of the transmission provider. Thus, we believe that additional reporting requirements may be necessary to detect undue discrimination. Accordingly, we propose to add a requirement in our regulations for transmission providers to post on OASIS certain metrics related to the provision of transmission service under the pro forma OATT. Specifically, we propose to require transmission providers to post data each month concerning transmission service requests associated with particular paths or flowgates that would clearly identify the number of requests that have been accepted and the number of requests that have been denied during the prior month. The posted data would show: (1) the number of non-affiliate requests for transmission service that have been rejected and (2) the total number of non-affiliate

requests for transmission service that have been made. This posting would distinguish between the length of the service request (e.g., short-term or long-term requests) and between the type of service requested (e.g., firm point-to-point, non-firm point-to-point or network service). We also propose that the transmission provider post similar information for affiliate transactions. In other words, the transmission provider would also post: (1) the number of affiliate requests for transmission service that have been rejected, and (2) the total number of affiliate requests for transmission service that have been made. Similarly, this posting would distinguish between the length of the service request (e.g., short-term or long-term requests) and between the type of service requested (e.g., firm point-to-point, non-firm point-to-point or network service).

194. Another area of discretion is the load forecasts used by the transmission provider when computing ATC. The Commission recognizes that the lack of transparency regarding transmission providers' forecasted and actual use of the transmission system makes it difficult to determine whether an appropriate amount of capacity is being set aside for service to native load. To address this concern, we are considering additional posting requirements. For example, should transmission providers make available their underlying load forecast assumptions for all ATC calculations? In addition, should transmission providers post, on a daily basis, their actual daily peak load for the prior day? We believe that this posting of forecasted and actual loads would allow the Commission and others to make a meaningful comparison of these elements. We invite comment on whether this information would be helpful for such a comparison. We also

seek comment on the overall benefits of posting metrics and on potential alternative metrics.

195. For all of our proposed OASIS reforms, we propose to require public utilities, working through NAESB, to develop standards for consistent methods of posting the new requirements on OASIS so that a common format is used.

B. Transmission Planning – Coordinated, Open and Transparent Planning

196. Order No. 888 set forth certain minimum requirements for transmission system planning. For example, the pro forma OATT requires transmission providers to plan for the transmission needs of their network customers on a comparable basis (section 28.2), and it requires them to expand their systems to accommodate firm point-to-point customer requests (sections 13.5 and 15.4) that cannot be satisfied due to transmission constraints or satisfied more economically via redispatch. In addition, in Order No. 888-A, the Commission encouraged utilities to engage in joint planning with other utilities and customers and to allow affected customers to participate in facilities studies to the extent practicable. The Commission also encouraged regional planning so that the needs of all participants are represented in the planning process.[184] However, the Commission did not require joint planning between transmission providers and their

[184] See Order No. 888-A at 30,311.

customers or between transmission providers in a given region,[185] nor did it impose any specific requirements regarding the manner in which transmission providers should coordinate their transmission system planning with their pro forma OATT customers. The only section of the pro forma OATT that directly speaks to joint planning is section 30.9, which provides that for facilities constructed by a network customer, the network customer must receive credit where such facilities are jointly planned and installed in coordination with the transmission provider.[186]

197. In the NOI, the Commission asked several questions about joint planning between transmission providers and their customers. For example, we asked whether joint planning should be made mandatory, particularly when transmission requests affect adjacent transmission systems. We also inquired whether joint planning should be subject to an annual reporting requirement or audits. Additionally, we asked for comment on a number of issues designed to determine whether any pro forma OATT reforms are necessary to ensure that the transmission system is expanded so that customers have adequate transmission service. As the comments below indicate, commenters generally all believe that joint and regional planning are necessary and

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[185] See id.

[186] Pro forma OATT section 21.2, "Coordination of Third-Party System Additions," provides for certain rights for transmission providers to coordinate construction of facilities on their systems associated with point-to-point customer requests and related construction on a third-party transmission system, but imposes no obligation on transmission providers.

desirable, but there is a split over whether it should continue to be voluntary or should be made a requirement.

Comments Supportive of Mandatory Joint and Regional Planning

198. A number of commenters contend that joint planning between transmission providers and their customers should be required by the pro forma OATT. Most of these commenters also advocate joint planning among transmission providers in a given region. In perhaps the strongest comments on the topic, TDU Systems and TAPS request that the Commission mandate an open, regional transmission expansion planning process that provides opportunities for transmission customers to join and participate in the planning process. Many other commenters also support joint and regional planning in some form or another, with some focusing particularly on requiring such planning when adjacent transmission systems are affected.[187] Bonneville and Williams also assert that there is already Commission precedent for joint planning in our procedures on large generator interconnections, which require the coordination of studies when interconnection requests affect other systems. EPSA states that the Commission should require that neighboring systems formalize the process under which broad regional models are developed and used to study requests on any system within a broadly defined region. Powerex points out that

[187] E.g., AEP, Alcoa, APPA, Bonneville, Calpine, EPSA, Lafayette, National Grid, NCPA, NRECA, Old Dominion, Trans-Elect, Williams, and Xcel. Though it does not generally support mandatory joint and regional planning, EEI recommends that the Commission modify the pro forma OATT to address planning when transmission requests require upgrades on or otherwise adversely affect adjacent transmission systems.

the lack of regional transmission planning is one of the most difficult issues faced in the Pacific Northwest, and PPL asserts that transmission planning and expansion in the Western Interconnection does not support a competitive market.

199. In addition, many commenters contend that transmission providers should be required to report on an annual basis the joint and regional planning that has occurred or been requested.[188] TAPS states that an annual filing noticed by the Commission that gives the public an opportunity to comment should be buttressed with audits, in order to ensure that transmission providers are taking joint planning with their network customers (and neighboring systems) seriously. EPSA likewise contends that transmission providers should be required to report to the Commission on an annual basis the joint planning that has occurred or been requested on their systems, and that the Commission should conduct audits to determine the level of compliance with any joint planning requirement or agreement.

200. The commenters that advocate mandatory joint and regional planning assert that it is needed because transmission providers unduly discriminate against their customers when planning their transmission systems. For example, a number of commenters assert that transmission providers meet their own needs for transmission planning and construction before (and often without) meeting those of their customers.[189] NRECA

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[188] E.g., East Texas Cooperatives, EPSA, FMPA, MidAmerican, and TAPS.

[189] E.g., FMPA, Midwest Municipals, NCPA, and NRECA.

asserts that since the implementation of Order No. 888, a number of public utility transmission providers – despite clearly stated obligations in the pro forma OATT – have not planned for their load-serving transmission customers on a basis comparable to that of their own bundled retail native load. TDU Systems believe that joint and regional transmission planning is a critical component of ensuring comparability between a transmission provider's use of the transmission system and a network customer's use of the transmission system, largely because transmission providers have an incentive to thwart the expansion planning process. Both NRECA and TDU Systems argue that the planning processes in RTOs and ISOs also are insufficient because they often only allow customer input after transmission plans are developed by individual transmission providers.

201. TAPS asserts that the absence of joint planning has resulted in unduly discriminatory transmission service. For comparable service to be a reality, TAPS asserts that the transmission system must be planned and built for customer needs, just as it must be planned and built to meet the transmission providers' need to provide service to their native loads. Old Dominion contends that transmission providers often locate transmission in such a way that it favors their own generation. According to Lafayette, transmission providers have increased their generation dominance by inadequately planning for the needs of their transmission customers so that they are unable to turn to alternative suppliers. East Texas Cooperatives also argues that some transmission providers continue to plan their systems in isolation from the needs of other load-serving

entities. EPSA concludes that the transmission needs of non-transmission provider customers are simply not integrated effectively into the planning process. APPA notes that the original goal of the pro forma OATT -- an inclusive planning process that takes into account on a comparable basis the load growth and new generation resource needs of all loads served using the transmission provider's system -- has not been achieved. Many commenters assert that joint and regional transmission planning is necessary in order to ensure adequate infrastructure development.[190] Others focus on the need for joint and regional planning to address the fact that changes on one system often affect transmission service on adjacent systems.[191] Lastly, APPA blames substantial and rising congestion costs on inadequate transmission planning, and EPSA contends that better transmission planning is needed to support a competitive electricity market.

Comments Supportive of Voluntary Joint and Regional Planning

202. Another large group of commenters, including many investor-owned utilities, stress that joint and regional planning, while laudable, should not be mandatory and that it should continue to be voluntary or that processes are already in place to encourage

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[190] E.g., AEP, Calpine, Constellation, East Texas Cooperatives, ELCON, NRECA, and TransAlta.

[191] E.g., Alcoa and EPSA. EEI acknowledges the planning difficulties that arise when a transmission request on one system causes the need for upgrades to another system.

regional planning.[192] Progress Energy, for example, contends that there are several formalized processes in place today that foster joint and regional planning, such as the process in North Carolina. Southern points out that in addition to participating in Southeastern Electric Reliability Council (SERC) planning activities, it is engaged in other types of joint regional planning (e.g., through the Georgia Integrated Transmission System (Georgia ITS)).[193] Nevada Companies supports the approach already used in the WECC, which employs interconnection-wide models for planning. Nevada Companies explains that these studies are then made available to all other WECC transmission providers. In addition, APS, Tacoma, and WAPA point to numerous forums (e.g., the Southwest Area Transmission planning group and the Southwest Transmission Expansion Plan process) where transmission providers and other industry stakeholders coordinate their transmission plans. LPPC also states that the Georgia ITS has provided benefits to participants and the region – in the form of improved investment in infrastructure and through the introduction of new sources of capital. Lastly, some

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[192] E.g., Cinergy, Entergy, KCP&L, LPPC, MidAmerican, Nevada Companies, North Carolina Commission, Northwestern, PNM-TNMP, Progress Energy, Salt River, Snohomish, South Carolina Regulatory Staff, Southern, Tacoma, and WAPA. Nevertheless, KCP&L, Nevada Companies, and Progress Energy join with EPSA in calling for a more formalized process for addressing base case and expansion plans.

[193] Georgia ITS consists of jointly-owned transmission facilities, which are owned by the Southern subsidiary Georgia Power, the Municipal Electric Authority of Georgia, the Georgia Transmission Corporation – a cooperative utility – and Dalton Utilities – a municipal system.

commenters point out that collaborative regional planning already occurs in RTO and ISO regions.[194] With regard to PJM, however, TDU Systems argues that better transmission planning is required due to PJM's "rubber-stamping" of transmission provider identified transmission upgrades. Exelon states that the Northeastern ISO/RTO Planning Coordination Protocol is a formal agreement, executed in 2004, among the PJM Interconnection, the New York Independent System Operator, and ISO New England, pursuant to which the three organizations conduct a comprehensive process of coordinating system planning activities.

203. With regard to the imposition of reporting requirements, many commenters argue that transmission providers already are required to report joint planning activities.[195] EEI, for example, contends that joint planning activities under section 30.9 of the pro forma OATT currently are required to be reported on each transmission provider's OASIS. EEI argues that audits should not be required. Bonneville contends that, at least in the Pacific Northwest, annual reporting and audits are not needed. Bonneville states that transmission planning staffs already bear a heavy workload; for example, Bonneville's planning staff must address many requests for transmission and interconnection service, as well as conduct regional planning efforts and comply with regional and national reliability initiatives. Northwestern states that reporting

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[194] E.g., Ameren, CAISO, Exelon, ISO New England, and MidAmerican.

[195] E.g., Bonneville, EEI, KCP&L, PNM-TNMP, Salt River, Tacoma, and WAPA.

requirements or audits are not needed and would be burdensome to the transmission provider, distracting it from performing its joint planning responsibilities.

Current pro forma OATT Planning Responsibilities

204. Order No. 888 and the pro forma OATT require that transmission providers plan and upgrade their transmission systems to provide comparable open access transmission service for their transmission customers. For example, with regard to network service, section 28.2 of the pro forma OATT provides that the transmission provider "will plan, construct, operate and maintain its Transmission System in accordance with Good Utility Practice in order to provide the Network Customer with Network Integration Transmission Service over the Transmission Provider's Transmission System." Section 28.2 also provides that the Transmission Provider shall, consistent with Good Utility Practice, "endeavor to construct and place into service sufficient transfer capability to deliver the Network Customer's Network Resources to serve its Network Load on a basis comparable to the Transmission Provider's delivery of its own generating and purchased resources to its Native Load Customers."

205. The pro forma OATT also requires that new facilities be constructed to meet the service requests of long-term firm point-to-point customers. Section 13.5 of the pro forma OATT requires the transmission provider to consider redispatch of the system to relieve any constraints that are inhibiting a transmission customer's point-to-point service if it is economical to do so; but if redispatch is not economical, the transmission provider is obligated to expand or upgrade its system. This expansion obligation on the part of the

transmission provider for point-to-point service is found in section 15.4 of the pro forma OATT, which provides that when a transmission provider cannot accommodate a point-to-point transaction because of insufficient capability on its system, it will "use due diligence to expand or modify its Transmission System to provide the requested Firm Transmission Service." Section 15.4 goes on to provide that "the Transmission Provider will conform to Good Utility Practice in determining the need for new facilities and in the design and construction of such facilities." Importantly, however, the transmission provider's obligation to upgrade or expand its system to provide point-to-point service as detailed in section 15.4 is contingent on the transmission customer agreeing to compensate the transmission provider for such costs pursuant to the terms of section 27 (providing for cost responsibility for upgrades and/or redispatch "to the extent consistent with Commission policy"). Order No. 888 does not, however, require that transmission providers coordinate with either their network or point-to-point customers in transmission planning or otherwise publish the criteria, assumptions, or data underlying their transmission plans.[196]

[196] Certain transmission data is required to be provided annually in the FERC Form 715 (e.g., Part 2 – Power Flow Base Cases, Part 3 – Transmitting Utility Maps and Diagrams, Part 4 – Transmission Planning Reliability Criteria, Part 5 – Transmission Planning Assessment Practices, and Part 6 – Evaluation of Transmission System Performance). As discussed below, we do not believe that the FERC Form 715 reporting requirements have satisfied the need for transparency with regard to transmission planning.

The Need for Reform

206. As discussed more fully in Part III.C above, in the ten years since Order No. 888 was issued, the Nation has witnessed a decline in transmission investment relative to load growth. As a result, transmission capacity per MW of peak demand has declined in every NERC region, and it has been estimated that capital spending must increase significantly to ensure system reliability and to accommodate wholesale electric markets. Many have argued that inadequate expansion of the transmission grid has contributed to the widespread transmission constraints that plague most regions of the country, as reflected in the limited amounts of ATC posted in many regions, increased frequency of denied transmission services requests, and increasingly common transmission service interruptions or curtailments, all of which make it more difficult for transmission customers to transfer power. In short, it has become clear that since Order No. 888 was issued, the Nation's transmission grid has not been planned and developed adequately and projections suggest that without reform this trend will continue.

207. The need for transmission planning reform also has been recognized by the Consumer Energy Council of America (CECA), a public interest energy policy organization with a 30-year history of bringing stakeholders together to find solutions to contentious energy policy issues. CECA launched its Transmission Infrastructure Forum

in early 2004,[197] which published its conclusions in January 2005 in a final report titled "Keeping the Power Flowing: Ensuring a Strong Transmission System to Support Consumer Needs for Cost-Effectiveness, Security and Reliability" (CECA Report).[198] Among other things, the CECA Report concludes that regional transmission planning with consumer input early in the process is needed to ensure the development of a robust transmission system capable of meeting consumer needs reliably and at reasonable cost over time. The CECA Report stresses that regional transmission planning must address inter-regional coordination, the need for both reliability and economic upgrades to the system, as well as critical infrastructure to support national security and environmental concerns.[199]

208. Transmission providers have a disincentive to remedy transmission congestion when doing so reduces the value of their generation or otherwise stimulates new entry or greater competition in their area. As the Commission noted in Order No. 888, "[i]t is in the economic self-interest of transmission monopolists, particularly those with high-cost

[197] The CECA Transmission Infrastructure Forum included representatives from such diverse constituencies as investor-owned utilities, rural electric cooperatives, municipal power systems, federal power systems, independent power producers, equipment manufacturers, the U.S. Congress, the Commission, the U.S. Department of Energy, state legislatures, state public utility commissions, state energy offices and consumer advocates, consumer and environmental organizations, independent consultants, and academic institutions.

[198] Available at http://www.cecarf.org/Publications/PublicationsAllDate.html.

[199] See, e.g., CECA Report at 10-11.

generation assets, to deny transmission or to offer transmission on a basis that is inferior to that which they provide themselves."[200] This statement continues to be true today. In upholding the Commission's authority to require open access in Order No. 888, the court in TAPS v. FERC noted that "[u]tilities that own or control transmission facilities naturally wish to maximize profit. The transmission-owning utilities thus can be expected to act in their own interest to maintain their monopoly and to use that position to retain or expand the market share for their own generated electricity, even if they do so at the expense of lower-cost generation companies and consumers."[201] Thus, even when transmission providers do address congestion, they have an incentive to do so in a manner that benefits their own generation or loads rather than the generation or loads of their competitors. These disincentives frustrate new investment that could remedy both "local" congestion (i.e., within the transmission provider's control area) and congestion between control areas, as well as remedy undue discrimination and increase bulk power trade. For example, a transmission provider does not have an incentive to relieve local congestion that restricts the output of a competing merchant generator if doing so will

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[200] Order No. 888 at 31,682.

[201] 225 F.3d at 684; see also New York v. FERC, 535 U.S. at 8-9 (addressing Order No. 888's open access requirements, the Court noted that "public utilities retain ownership of the transmission lines that must be used by their competitors to deliver electric energy to wholesale and retail customers. The utilities' control of transmission facilities gives them the power either to refuse to deliver energy produced by competitors or to deliver competitors' power on terms and conditions less favorable than those they apply to their own transmissions.") (citation and footnote omitted).

make the transmission provider's own generation less competitive. A transmission provider also does not have an incentive to increase the import or export capacity of its transmission system if doing so would allow cheaper power to displace its higher cost generation or otherwise make new entry more profitable by facilitating exports.

209. The existing pro forma OATT does not adequately address the above-referenced problems. As noted, there is no general requirement that a transmission provider coordinate its transmission planning with customers, market participants, or its interconnected neighbors.[202] Additionally, though the pro forma OATT does require transmission providers to plan for the needs of their network customers and to expand their systems to provide service to point-to-point customers, there is no requirement that the overall transmission planning process be open to customers, competitors, and state commissions. Rather, the transmission provider currently is allowed to create its own transmission plan with limited or no input from affected market participants or other affected entities, such as state commissions. There is also no requirement that the planning process be transparent. While we recognize that certain planning information is required to be filed annually in FERC Form No. 714 – Annual Electric Control and Planning Area Report and FERC Form 715 – Annual Transmission Planning and

[202] As discussed more fully in Part V.C.2, section 30.9 of the current pro forma OATT may inhibit coordinated planning by making transmission providers reluctant to engage in coordinated planning, because of the requirement to give customers credits for jointly planned facilities. We are proposing to sever the link between credits and planning, and treat the two issues separately within the pro forma OATT.

Evaluation Report, this does not appear to provide sufficient transparency to remedy the remaining concerns expressed in this proceeding about the potential for undue discrimination in planning.

210. Taken together, this lack of coordination, openness, and transparency results in opportunities for undue discrimination in transmission planning. Without adequate coordination and open participation, market participants have no input into whether a particular plan treats all loads and generators comparably. Without sufficient transparency, market participants have no means to determine whether the plan developed by the transmission provider in isolation is discriminatory. Moreover, the process is inefficient. Disputes over discrimination occur primarily after-the-fact because there is insufficient coordination and transparency between transmission providers and their customers for purposes of planning. The Commission has a duty to prevent undue discrimination in the rates, terms, and conditions of public utility transmission service, and therefore, an obligation to remedy these transmission planning deficiencies. The Commission's authority to remedy undue discrimination is broad.[203] In addition, new section 217 of the FPA requires the Commission to use its FPA authorities in a manner that facilitates the planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities. Finally, we note that a more transparent and

[203] See Order No. 888 at 31,669 (noting that the FPA "fairly bristles" with concern for undue discrimination (citing Associated Gas Distributors v. FERC, 824 F.2d 981, 998 (D.C. Cir. 1987)).

coordinated regional planning process can support the DOE's responsibilities under EPAct 2005 section 1221 to study transmission congestion and issue reports designating National Interest Transmission Corridors.

211. We are encouraged that since the adoption of open access in Order No. 888, a number of voluntary coordinated and regional planning efforts have been developed throughout the country, including those administered by RTOs and ISOs. For example, each of the Commission-approved RTOs in the Northeast, Midwest and Southwest, as well as CAISO, provide for a coordinated and regional planning process with stakeholder input from each industry segment. The Commission also notes that there are several other promising efforts to establish voluntary coordinated and regional planning efforts around the country. For example, WECC is in the process of expanding its reliability responsibilities to include comprehensive transmission planning to address the regional economic transmission needs of its members and other stakeholders in its regional footprint. In addition, each of the subregions in WECC has a coordinated transmission planning process that, in varying degrees, is open to market participants and, in some instances, has resulted in significant new transmission being built on a joint ownership basis. In North Carolina, Duke, Progress Energy, and two other organizations – North Carolina Electric Membership Corporation and ElectriCities of North Carolina, Inc. – have endeavored to create and implement a collaborative electric transmission planning process in that state. This process provides for broad stakeholder input as well an

independent facilitator. Other models for coordinated planning include the Georgia ITS and joint ownership arrangements like it around the country.

212. We fully support these voluntary efforts and believe they are consistent in significant respects with the nature of the reforms we are proposing for transmission planning under the pro forma OATT. In those regions and subregions that already have adopted significant reforms, our proposal may require only modest changes, while other regions and subregions may need to undertake more significant changes to the way in which the transmission system is planned today.

213. Today, numerous competing interests have a need to utilize the transmission grid, and yet in many areas of the country that grid is planned much the same way as it was before the electric industry matured into a regional business and Order No. 888 was implemented. That is, the same public utilities that own and control the grid also control the planning process that governs when and how the grid is expanded and upgraded. In short, the transmission grid is being utilized in a fundamentally different way, consistent with the intent of open access, and a decade of experience has shown us that in order to remedy undue discrimination, the existing provisions of the pro forma OATT respecting transmission system planning must be reformed. Accordingly, in order to provide for more comparable open access transmission service, eliminate the potential for undue discrimination and anticompetitive conduct, and satisfy our statutory responsibilities under section 217 of the FPA, we propose that each public utility transmission provider participate in an open and transparent local and regional planning process that addresses

certain fundamental principles of transmission planning. As we indicated above, existing regional planning processes will be expected to meet or exceed the transmission planning principles we outline in this proposed rule.

Coordinated, Open, and Transparent Transmission Planning

214. In order to eliminate the potential for undue discrimination as described above, and to ensure that comparable transmission service is provided by all public utility transmission providers, including RTOs and ISOs, we propose to amend the pro forma OATT to require coordinated, open, and transparent transmission planning on both a local and regional level. We propose to require each public utility transmission provider to submit, as part of its compliance filing in this proceeding, a proposal for a coordinated and regional planning process that complies with the following coordinated and regional planning principles.[204] In the alternative, transmission providers may make a compliance filing in this proceeding describing their existing coordinated and regional planning process and showing that it is consistent with or superior to the requirements set forth below. Moreover, we expect municipal, cooperative, and other public power entities to participate in these processes as well, consistent with their obligation to provide reciprocal transmission service as detailed in Order No. 888. An open and transparent regional planning process cannot succeed unless all transmission owners participate.

[204] The revised pro forma OATT reflects the proposed planning requirement in sections 15.4, 16.1, 17.2(x), 28.2, 29.2, 31.6, and Attachment K.

Under our proposal in this NOPR, a coordinated, open and transparent process must satisfy the following eight principles:

1. Coordination – The transmission provider must meet with all its transmission customers and interconnected neighbors to develop a transmission plan on a nondiscriminatory basis. The Commission seeks comment on specific requirements for this coordination, such as the minimum number of meetings to be required each year, the scope of the meetings, the notice requirements, the format, and any other features deemed important by commenters.
2. Openness – Transmission planning meetings must be open to all affected parties (including all transmission and interconnection customers, and state commissions). The Commission seeks comment on whether there are any circumstances under which participation should be limited, e.g., to address confidentiality concerns.
3. Transparency – The transmission provider is required to disclose to all customers and other stakeholders the basic criteria, assumptions, and data that underlie its transmission system plans. The Commission seeks comment on whether the information provided in FERC Form 715 is adequate and, if not, what additional detail should be provided. The Commission also seeks comment on the format for disclosure, including protections to address confidentiality concerns.

4. Information Exchange – Network transmission customers are required to submit information on their projected loads and resources on a comparable basis (e.g., planning horizon and format) as used by transmission providers in planning for their native load; and point-to-point customers are required to submit any projections they have of a need for service over the planning horizon and at what receipt and delivery points. The Commission seeks comment on whether specific requirements should be adopted for this information exchange.[205] The transmission provider must allow market participants the opportunity to review and comment on draft transmission plans.
5. Comparability – After considering the data and comments supplied by market participants, the transmission provider is to develop a transmission system plan that: (1) meets the specific service requests of its transmission customers; and (2) otherwise treats similarly situated customers (e.g., network and retail native load) comparably in transmission system planning.

[205] For network service, some of this information already is required by sections 29, 30 and 31 of the pro forma OATT, but to the extent it is not, we propose to require customers to provide additional information as necessary for the transmission provider to develop a system plan.

6. Dispute Resolution – The transmission provider must propose a dispute resolution process, such as requiring senior executives to meet prior to the filing of any complaint and using a third-party neutral. The Commission's Dispute Resolution Service is available to assist transmission providers in developing a dispute resolution process. In addition to informal dispute resolution, affected parties would have the right to file complaints with the Commission under FPA section 206. The Commission seeks comment on whether any specific dispute resolution processes should be required.

7. Regional Participation – In addition to preparing a system plan for its own control area on an open and nondiscriminatory basis, the transmission provider is required to coordinate with interconnected systems to: (1) share system plans to ensure that they are simultaneously feasible and otherwise use consistent assumptions and data, and (2) identify system enhancements that could relieve "significant and recurring" transmission congestion (defined below). The Commission strongly encourages that such coordination encompass as broad a region as possible, given the interconnected nature of the transmission grid and the efficiency of addressing these issues in a single forum. The Commission also recognizes that, as in the West, it may be appropriate to organize regional planning efforts on both a subregional and regional level. The Commission seeks comment on whether there are existing institutions (such as the NERC

regional councils or subregional planning groups) that are well situated to perform or coordinate this function.

8. Congestion Studies – The transmission provider is required annually to prepare studies identifying “significant and recurring” congestion and post such studies on its OASIS. The studies should analyze and report on the location and magnitude of the congestion; possible remedies for the elimination of the congestion, in whole or in part; the associated costs of congestion; and the cost associated with relieving congestion through system enhancements (or other means). The Commission seeks comment on how to define “significant and recurring” congestion, such as by reference to generation redispatch, repeated denials of service requests, zero ATC, frequent curtailments or a combination of these factors. The required congestion studies would address both “local” congestion (i.e., within the transmission provider’s system) and congestion between control areas and subregions. The purpose of this requirement is to ensure that affected market participants, state commissions, and this Commission understand both the costs of recurring transmission congestion and the remedies. The Commission seeks comment on how this information should be used by the transmission provider and market participants to address significant and recurring congestion.

215. The Commission encourages the use of an independent third party to oversee or coordinate the planning process. The Commission is not proposing to require an independent third party to control the process, but does believe that independence can provide greater confidence in the planning process and resulting studies. Independence can take many forms, from having an independent entity resolve disputes over planning assumptions and decisions (as in an RTO) to having an independent consultant coordinate and otherwise perform the annual congestion studies referred to above. The Commission seeks comment on the levels of independence that can provide benefits and the institutions that could offer such independence, such as whether Regional Entities under the ERO could provide such independence.

216. Additionally, the Commission strongly encourages the participation of state commissions and other state agencies, particularly with regard to regional planning, in the coordinated transmission planning processes being proposed in this NOPR. The participation and support of state commissions and other state agencies is important because state commissions regulate the cost of transmission that is included in bundled retail rates and states also perform transmission siting. Many states also have traditionally been involved in utility planning in some way for their state or region. The Commission seeks comment on how best to accommodate effective state participation.

217. The Commission seeks comment on several aspects of this proposal. First, the Commission seeks comment on how much flexibility each transmission provider in a region should be given in implementing any principles adopted. Second, the Commission

seeks comment, by way of examples, on transmission planning processes that comply with the proposed transmission planning reforms in principle.

218. Third, we seek comment on whether there are other principles or requirements that should be adopted to support the construction of needed new infrastructure and otherwise ensure that all market participants are treated on a comparable basis. For example:

a. We seek comment on whether there should be a principle or guideline to govern the recovery and allocation of costs associated with funding the regional planning requirement. To devote the resources necessary to support an open and transparent regional planning process, we recognize that the participating entities must be assured of recovery of their costs, as well as assured that the costs will be borne equitably by all parties benefiting from the process.

b. We seek comment on whether there should be a requirement that, at least for large new transmission projects (such as new regional backbone facilities), there be an open season to allow market participants to participate in joint ownership of these projects. We believe that such a requirement could stimulate more investment in the grid and ensure that all customers have the ability to participate in new projects on a nondiscriminatory basis, including smaller market participants that cannot support the construction of large new facilities on their own.[206] We seek comment on whether to include such a requirement and, if so, what conditions or limitations should be associated with it.

c. We further seek comment on whether there should be a specific study process to identify opportunities to enhance the grid for purposes beyond maintaining reliability or reducing current congestion. Such a process would allow interested entities, including state resource agencies, siting bodies and commissions, load-serving entities, or other market participants to request that the transmission provider model grid upgrades needed to accommodate the construction of new resources, e.g., remote coal, nuclear or wind on a local and regional basis and prior to the existence of an actual proposal for such resources. Such a process could provide the information necessary to allow interested entities to proactively evaluate, on a nondiscriminatory basis, different resource options in light of the differing

[206] We note that transmission providers in the Western Interconnection already participate in regional and sub-regional transmission planning processes that include the opportunity for joint financing and ownership of transmission facilities. Such facilities are typically owned by the participants as “tenants in common” with each participant owning a pro rata share of the land and common facilities and sharing the costs and expenses in proportion to their ownership percentage in each project. Additionally, all owners participate in the oversight and administration of jointly-owned projects through representation on various administration committees. Among other benefits, this has allowed all participating utilities, large and small, to take advantage of the economies of scale associated with larger transmission projects.

transmission infrastructure needs associated with them. We recognize that resource planning is traditionally performed at the state level and do not believe that any such study process would conflict with these state prerogatives. To the contrary, we believe such a study process could provide states better information to evaluate all relevant resource options in exercising their resource adequacy authority.

d. We also seek comment on whether we should require public utilities to develop cost allocation principles to address the sharing of the costs of new transmission projects. Would the development of specific cost allocation principles provide greater certainty and hence support the construction of new infrastructure? Or is cost allocation better handled on a case-by-case basis? We also seek comment on how, as part of any cost allocation process, to address the fact that upgrades that may not be needed for reliability in the near term (e.g., 3-5 years) may be necessary to support reliability in the longer term (e.g., 10-15 years). Furthermore, because transmission upgrades, particularly multi-state regional backbone facilities, often can require 10 to 15 years to construct, we seek comment on whether the planning process proposed here should be required to look out at least as far as the longest time it would take to build such an upgrade in the region in question.

219. Finally, the Commission seeks comment on the level of detail to be required in transmission providers' OATTs.

C. Transmission Pricing

220. Order No. 888 and the pro forma OATT included primarily non-rate terms and conditions of open access non-discriminatory transmission service. The Commission required transmission providers to propose corresponding rates in a subsequent filing under FPA section 205. Similarly, here we do not propose to undertake a comprehensive overhaul of our transmission pricing policies. We do, however, propose a number of reforms to several discrete provisions in the pro forma OATT, as further described below. We also provide a clarification of our policy for pricing of system expansions.

1. Imbalances

Energy Imbalances

221. In Order No. 888, the Commission concluded that six ancillary services must be included in an OATT.[207] One of those ancillary services is energy imbalance service under Schedule 4 of the pro forma OATT.[208] Energy imbalance service is provided when the transmission provider makes up for any difference that occurs over a single hour between the scheduled and the actual delivery of energy to a load located within its

[207] Order No. 888 at 31,703.

[208] Id.

Comment Form for First Posting revisions to MOD-001-1 Documentation of Total Transfer Capability and Available Transfer Capability Calculation Methodologies

Please use this form to submit comments on the first draft of the ATC/TTC Methodology Documentation Standard. Comments must be submitted by **June 28, 2006**. You must submit the completed form by emailing it to sarcomm@nerc.com with the words “ATC/TTC Methodology” in the subject line. If you have questions please contact Maureen Long at maureen.long@nerc.net or 813-468-5998.

ALL DATA ON THIS FORM WILL BE TRANSFERRED AUTOMATICALLY TO A DATABASE.

DO: **Do** enter text only, with no formatting or styles added.
Do use punctuation and capitalization as needed (except quotations).
Do use more than one form if responses do not fit in the spaces provided.
Do submit any formatted text or markups in a separate WORD file.

DO NOT: **Do not** insert tabs or paragraph returns in any data field.
Do not use numbering or bullets in any data field.
Do not use quotation marks in any data field.
Do not submit a response in an unprotected copy of this form.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT** ☐ **FRCC** ☐ **MRO** ☐ **NPCC** ☐ **RFC** ☐ **SERC** ☐ **SPP** ☐ **WECC** ☐ **NA – Not Applicable**	☐	1 — Transmission Owners
	☐	2 — RTOs, ISOs, Regional Reliability Councils
	☐	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

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on the prior page.

Background Information

The Long-Term AFC/ATC Task Force (LTATF) was formed to develop specific recommendations for the calculation and coordination of AFC/ATC with the goal of increasing market liquidity and enhancing grid reliability. The task force's work was coordinated with NAESB to separate business practices from reliability concerns. The LTATF evaluated the results of the short-term recommendations in the Alliant West area for summer 2004, and used this evaluation when considering whether to recommend the Alliant West short-term recommendations continue. The work resulted in the formation of a SAR Drafting Team who formed recommendations that are the basis for the formation of a Standard Drafting Team.

In developing their recommendations the NERC LTATF considered the calculation for AFC/ATC, communication and coordination of AFC/ATC, and consistency between transmission planning and AFC/ATC calculations. A final LTATF report was presented to the Standing Committees in March 2005. The task force used the report and recommendations to develop proposed standards for ATC/TTC and CBM/TRM. The proposed "Modification to MOD-001-0 Documentation of ATC and TTC Calculation" Standard is the culmination of the work of the NERC LTATF and Standard Drafting Team and is the subject matter for this Comment Form.

The SAC and Standard Drafting Team (ATCTDT) would like to receive industry comment on the proposed Standard.

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

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree with the definition of terms used in the revised standard?

   ☐ Yes

   ☐ No

   Comments:

2. Does the revised standard include the correct entities in the applicability section of the standard?

   ☐ Yes

   ☐ No

   Comments:

3. Should the revised standard include a requirement for all entities that calculate TTC/ATC or AFC's to comply with the methodologies within this standard?

   ☐ Yes

   ☐ No

   Comments:

4. There are two identified methodologies. (Network Response and Rated System Path methodologies described in the Available Transfer Capability Definitions and Determinations June 1996 Appendix A and Appendix B NERC reference document) (Due to the brief time the Standard Drafting Team has had to address the two methodologies and the complexity of the differences between the methodologies the drafting team has not built a consensus as to whether the Standard needs to be further separated and asks for industry comment to assist the team.) In developing this standard has the standard drafting team adequately separated the standard to address these methodologies?

   ☐ Yes

   ☐ No

   Comments:

5. Should there be separate standards for each methodology?

   ☐ Yes

   ☐ No

   Comments:

6. Do you agree with the proposed requirements included in the revised standard?

   ☐ Yes

   ☐ No

   Comments:

7. Is the scope of the draft standard sufficient to address reliability concerns?

   ☐ Yes

   ☐ No

   Comments:

8. Should the standard include further standardization for the calculation of TTC/ATC/AFC/?

   ☐ Yes

   ☐ No

   Comments:

9. Does the standard address the goal of the LTATF report to improve communication, coordination, standardization, and transparency?

   ☐ Yes

   ☐ No

   Comments:

10. Do you have other comments on the draft Standard?

    Comments:

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. SAC Authorized posting TTC/ATC/AFC SAR Development Jun 20 2005.
2. SAC Authorized for Development Feb 14 2006.
3. SAC appoints Standard Drafting Team Mar 17 2006.

Description of Current Draft:

First draft of standard posted for stakeholders comment.

Future Development Plan:

1. Post revised standard for stakeholder comments.	July 1 2006
2. Respond to comments.	August 14 2006
3. Post revised standard for stakeholder comment.	TBD
4. Respond to comments.	TBD
5. First ballot of standard.	TBD
6. Respond to comments.	TBD
7. Post for recirculation.	TBD
8. 30 Day posting before board adoption.	TBD
9. Board adopts MOD-001-1.	TBD
10. Effective date.	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.

Flowgate
A single transmission element, group of transmission elements and any associated contingency(ies) intended to model MW flow impact relating to transmission limitations and transmission service usage. Within the Interchange Distribution Calculator, Transfer Distribution Factors are calculated to approximate MW flow impact on the flowgate caused by power transfers.

Flowgate Rating: The amount of electric power that can flow across the Flowgate under specified system conditions without exceeding the physical capability of the facilities. Typically expressed in the form of thermal capability, however flowgates can be proxies for stability and other limiting criteria.

Available Flowgate Capability (AFC): A measure of the flow capability remaining in the Flowgate for further commercial activity over and above already committed uses. It is defined as the Flowgate Rating less the impacts of existing transmission commitments (including retail customer service), less the impacts of Capacity Benefit Margin and less the impacts of Transmission Reliability Margin.

Introduction

1. **Title:** **Documentation of Total Transfer Capability and Available Transfer Capability Calculation Methodologies**

2. **Number:** MOD-001-1

3. **Purpose:** The purpose of the standard is to promote the consistent and uniform application of Transfer Capability calculations among Transmission Service Providers. The standard will require methodologies to be developed and documented for calculating Total Transfer Capability (TTC) and Available Transfer Capability (ATC) or Flowgate Ratings and Available Flowgate Capability (AFC) that comply with NERC definitions for, TTC, ATC and AFC NERC Reliability Standards, and applicable Regional criteria.

4. **Applicability:**

   4.1. Regional Reliability Organization

   4.2. Transmission Service Provider

5. **Effective Date:** TBD

B. Requirements

R1. Each Regional Reliability Organization, in conjunction with its members, shall jointly develop and document a TTC/ATC methodology, Flowgate Rating/AFC methodology or both where applicable for scheduling, operating and planning horizons..

R1.1. A Transmission Service Provider that crosses one or more Regional Reliability Organization boundary may develop its own TTC/ATC or Flowgate Rating/AFC methodology and shall get approval for its methodology from each of the respective Regional Reliability Organization's or from NERC.

R1.2. Each Regional Reliability Organization shall post the most recent version of the TTC/ATC methodology, Flowgate Rating/AFC methodology or both on a publicly accessible web site and each Transmission Service Provider shall either reference or post the most recent version of the TTC/ ATC methodology or Flowgate Rating/AFC methodology on its OASIS. No data, which is subject to a non disclosure agreement will be posted on the Regional Reliability Organization's website or the OASIS.

R2. For each methodology listed below, the identified components shall be included:

R2.1. Rated System Path Methodology.

R2.1.1. The TTC section of the Rated System Path Methodology shall address each of the items listed below:

2.1.1.1. Identify the parties responsible for performing the calculations.

2.1.1.2. Identify the parties responsible for posting the result on OASIS.

2.1.1.3. Identify the parties that the data used in the calculation of TTC is coordinated with.

2.1.1.4. Explain how TTC is determined.

2.1.1.5. Identify all of the data required for the calculation of TTC. As a minimum, the following data must be identified and coordinated. To the extent that the data listed below is not used, provide an explanation.

2.1.1.5.1 **Transmission Outages**: Provide a list of the transmission system elements to be taken out of service.

2.1.1.5.2 **Powerflow model**: The baseline power flow model for calculating TTC will be made available to neighboring and affected calculators. Changes and upgrades to facilities that would affect the power flow model shall be provided to neighboring and affected calculators when revised.

2.1.1.5.3 **Path Definitions and Facility Ratings:** Path Definitions and Facility Ratings shall be exchanged with neighboring and affected calculators when revised.

2.1.1.6. Require that TTC values and their corresponding limiting factors be reviewed and updated when revised.

2.1.1.7. Describe the general approach to determine the contingencies considered in the TTC calculations.

2.1.1.8. Define the calculation horizons (e.g. scheduling horizon (same day and real-time), operating horizon (day ahead and pre-schedule) and planning horizon (beyond the operating horizon).

2.1.1.9. Define the Transmission Owner's and Transmission Planner's criteria used in the calculation of TTC for the scheduling, operating and planning horizons. Explain the rational between the criteria for the scheduling, operating and planning horizons.

2.1.1.10. Document the approved variances and the formal approval process.

2.1.1.11. Describe whether TTC postings are based upon simultaneous or non-simultaneous analysis.

R2.1.2. The ATC section of the Rated System Path Methodology shall address each of the items listed below:

2.1.2.1. Identify the parties responsible for performing the calculations.

2.1.2.2. Identify the parties responsible for posting the result on OASIS.

2.1.2.3. Explain how ATC is determined and its relationship to the TTC calculation. Identify how the reservations and schedules for Firm (non-recallable) and Non-firm (recallable) Transmission Service inside the Transmission Service Provider's system are accounted for in the ATC calculation.

2.1.2.4. Transmission Service Providers or entities responsible for posting ATC shall conform to FERC posting requirements.

2.1.2.5. Identify the parties that the data used in the calculation of ATC is coordinated with.

2.1.2.6. Identify all of the data required for the calculation of ATC. As a minimum, the following data must be identified and coordinated. To the extent that the data listed below is not used or shared, provide an explanation.:

2.1.2.6.1 **Committed Uses:** This information shall be provided and coordinated when revised.

2.1.2.6.2 **Transmission Service Requests**: This information shall be provided when revised.

2.1.2.7. Describe assumptions used for counterflow of transmission reservations, and or schedules, including the basis for the assumptions.

2.1.2.8. Define the Transmission Owner's and Transmission Planner's criteria used in the calculation of ATC for the scheduling, operating and planning horizons.

2.1.2.8.1 Compare and contrast the criteria used for each ATC calculation.

2.1.2.8.2 Identify those criteria which are consistent and those which are inconsistent across the scheduling, operating and planning calculation horizons

2.1.2.8.3 Identify those criteria which are consistent and those which are inconsistent with planning and operating criteria for the ATC Calculation.

2.1.2.8.4 Justify inconsistencies between ATC calculation criteria.

R2.1.3. Document the approved variances and the formal approval process.

R2.2. Network Response Methodology – TTC/ATC.

R2.2.1. Identification of the parties responsible for performing the calculations and posting the result on OASIS.

R2.2.2. Explanation of how TTC and ATC are determined and used in evaluating transmission service requests.

R2.2.3. Identification of which entities the data listed in the requirements below are shared with for the calculation of TTC and ATC values. To the extent that the data listed below is not used or shared, provide an explanation. The required minimum update periodicity for each item is listed below:

2.2.3.1. **Generation Outage Schedules**: This information shall be provided daily and when revised. The information exchanged shall differentiate between pending and approved outages.

2.2.3.2. **Generation dispatch order**: This information shall be provided daily and when revised.

2.2.3.3. **Transmission Outage Schedules**: This information shall be provided daily and when revised. The information exchanged shall differentiate between pending and approved outages.

2.2.3.4. **Interchange Schedules:** This information shall be provided daily and when revised.

2.2.3.5. **Transmission Service Requests**: This information shall be provided daily and when revised.

2.2.3.6. **Load Forecast**: This information shall be provided daily and when revised.

2.2.3.7. **Powerflow model**: The baseline power flow model for calculating TTC will be made available to neighboring/affected calculators. Changes/upgrades to facilities that would affect the power flow model shall be provided to neighboring/affected calculators when revised.

2.2.3.8. **TTC**: TTC will also be provided and exchanged.

R2.2.4. Describe how the assumptions for and the calculations of TTC and ATC values change over different scheduling, operating and planning horizons. including who is responsible for the calculations for the scheduling, operating and planning horizons.

R2.2.5. Require that TTC and ATC values and postings be reviewed and updated if changed. These values will be made available to other calculators and stakeholders at following intervals. These changes can be incremental.

2.2.5.1. Hourly TTC values will be calculated and posted hourly.

2.2.5.2. Daily TTC for current week at least once per day.

2.2.5.3. Daily TTC for day 8 through the first month at least once per week.

2.2.5.4. Monthly TTC values for months 2 through 13 at least once per month.

R2.2.6. Describe assumptions used for generation dispatch for both external and internal systems for base case dispatch and describe assumptions for transaction modeling, including the basis for the assumptions.

R2.2.7. Describe the general approach to determine the contingencies considered in the TTC calculations.

R2.2.8. Describe how the TTC methodologies are consistent with the Transmission Owner's/Transmission Planner's planning criteria and operating criteria for the scheduling, operating and planning calculation horizons.

2.2.8.1. Any variances must be approved by NERC or its designee.

R2.2.9. Describe whether TTC postings are based upon simultaneous or non-simultaneous analysis.

R2.2.10. Account for existing transmission commitments.

R2.2.11. Account for how the reservations and schedules for Firm (non-recallable) and Non- firm (recallable) Transmission Service, both within and outside the Transmission Service Provider's system, are included. An explanation must be provided on how reservations that exceed the capability of the specified source point are accounted for. (i.e. how does the Transmission Service Provider's calculation account for multiple concurrent requests for transmission service in excess of a generator's capacity or in excess of a Load Serving Entity's load)

R2.2.12. Describe how incomplete or so-called partial path transmission reservations are addressed. (Incomplete or partial path transmission reservations are those for which all transmission reservations necessary to complete the transmission path from ultimate source to ultimate sink are not identifiable due to differing reservation priorities, durations, or that the reservations have not all been made.)

R2.2.13. Account for the ultimate points of power injection (source) and power extraction (sink) in ATC calculations.

R2.2.14. Indicate the treatment and level of customer demands, including interruptible demands.

R2.2.15. Describe assumptions used for impacts and counterflow of transmission reservations, and or schedules, including the basis for the assumptions.

R2.2.16. Describe the formal process for the granting of any variances to the responsible parties identified in requirement 3.1. (Any variances must be approved by NERC or its designee).

R2.3. Network Response – AFC Methodology.

R2.3.1. Identification of the parties responsible for performing the calculations and posting the result on OASIS.

R2.3.2. Explanation of how AFC values are determined and used in evaluating transmission service requests. In addition, an explanation for all items listed here must also include any process that produces values that can override the AFC values.

R2.3.3. Account for existing transmission commitments.

R2.3.4. Account for how the reservations and schedules for Firm (non-recallable) and Non- firm (recallable) Transmission Service, both within and outside the Transmission Service Provider's system, are included. An explanation must be provided on how reservations that exceed the capability of the specified source point are accounted for. (i.e. how does the Transmission Service Provider's calculation account for multiple concurrent requests for transmission service in excess of a generator's capacity or in excess of a Load Serving Entity's load)

R2.3.5. Describe how incomplete or so-called partial path transmission reservations are addressed. (Incomplete or partial path transmission reservations are those for which all transmission reservations necessary to complete the transmission path from ultimate source to ultimate sink are not identifiable due to differing reservation priorities, durations, or that the reservations have not all been made.)

R2.3.6. Account for the ultimate points of power injection (source) and power extraction (sink) in AFC calculations.

R2.3.7. Require that AFC values and postings be reviewed and updated if changed. These values will be made available to other calculators and stakeholders at following intervals. These changes can be incremental.

2.3.7.1. Hourly AFC values will be calculated and posted hourly.

2.3.7.2. Daily AFC values for current week at least once per day.

2.3.7.3. Daily AFC values for day 8 through the first month at least once per week.

2.3.7.4. Monthly AFC values for months 2 through 13 at least once per month.

R2.3.8. Indicate the treatment and level of customer demands, including interruptible demands.

R2.3.9. Identification of which entities the data listed in the requirements below is shared with for the calculation of AFC values. To the extent that the data listed below is not used or shared, provide an explanation. The required minimum update periodicity for each item is listed below:

2.3.9.1. **Generation Outage Schedules**: This information shall be provided daily and when revised. The information exchanged shall differentiate between pending and approved outages.

2.3.9.2. **Generation dispatch order**: This information shall be provided daily and when revised.

2.3.9.3. **Transmission Outage Schedules**: This information shall be provided daily and when revised. The information exchanged shall differentiate between pending and approved outages.

2.3.9.4. **Interchange Schedules:** This information shall be provided daily and when revised.

2.3.9.5. **Transmission Service Requests**: This information shall be provided daily and when revised.

2.3.9.6. **Load Forecast** :) This information shall be provided daily and when revised.

2.3.9.7. **Powerflow model**: Updated models will be made available to neighboring/affected calculators. Changes/upgrades to facilities that would change the rating of the facilities that are limiting facilities shall be included in the models. This information shall be provided daily and when revised.

2.3.9.8. **Flowgate AFC data exchange:** Firm and non-firm AFC values shall be provided at the minimum update intervals as follows: Hourly AFC once-per-hour, Daily AFC once-per-day and Monthly AFC once-per-week.

2.3.9.9. **Flowgate Rating**: Flowgate Ratings will also be provided and exchanged. Entities identified in requirement 3.1 shall have the same Flowgate Rating as provided by the Transmission Owner of the facility. This information shall be provided when initially established or when revised.

2.3.9.10. **Criteria and definitions:** Flowgates and Flowgate definitions and criteria shall be exchanged with neighboring and affected calculators on a seasonal basis, or when revised.

R2.3.10. Describe how the assumptions for and the calculations of AFC values change over different scheduling, operating and planning horizons including who is responsible for the calculations for scheduling, operating and planning horizons.

R2.3.11. Describe assumptions used for impacts and counterflow of transmission reservations, and or schedules, including the basis for the assumptions.

R2.3.12. Describe assumptions used for generation dispatch for both external and internal systems for base case dispatch and transaction modeling, including the basis for the assumptions.

R2.3.13. Describe how the AFC methodologies are consistent with the Transmission Owner's/Transmission Planner's planning criteria and operating criteria for the appropriate calculation horizons.

R2.3.14. Any variances must be approved by NERC or its designee.

R2.4. Describe the formal process for the granting of any variances to the responsible parties identified in requirement 2.3.1. (Any variances must be approved by NERC or its designee).

C. Measures

M1. The Regional Reliability Organizations and Transmission Service Providers each have a documented TTC/Flowgate Rating and ATC/AFC methodology that includes all of the items identified in MOD-001-1 Requirement 1 through MOD-001-1 Requirement 3.12.

M2. The Regional Reliability Organization provides evidence that its TTC/Flowgate Rating and ATC/AFC methodology is available on a publicly accessible web site in accordance with Reliability Standard MOD-001-1_R1.2. The Transmission Service Providers shall provide evidence the methodology is posted on their OASIS site.

M3. The Regional Reliability Organizations and Transmission Service Providers each provide evidence that they have reviewed and approved the TTC/Flowgate Rating and ATC/AFC methodology to ensure it is consistent with Planning and Operating Criteria.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: NERC.

1.2. Compliance Monitoring Period and Reset Timeframe

Available on a publicly accessible web site.

1.3. Data Retention

None identified.

1.4. Additional Compliance Information

None.

2. **Levels of Non-Compliance**

   2.1. **Level 1:** The Regional Reliability Organization's documented TTC/Flowgate Rating methodology does not address one or two of the items required for documentation under Reliability Standard MOD-001-0_R1 and R2.

   2.2. **Level 1:** The Regional Reliability Organization's documented ATC/AFC methodology does not address one or two of the items required for documentation under Reliability Standard MOD-001-0_R1 and R3.

   2.3. **Level 2:** Not applicable.

   2.4. **Level 3:** Not applicable.

   2.5. **Level 4:** The Regional Reliability Organization's documented TTC/Flowgate Rating methodology does not address three or more of the items required for documentation under Reliability Standard MOD-001-1_R1 or R2.

   2.6. The Regional Reliability Organization's documented ATC/AFC methodology does not address three or more of the items required for documentation under Reliability Standard MOD-001-1_R1 or R3.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	January 13, 2006	Fixed numbering from R.5.1.1, R5.1.2., and R5.1.3 to R1.5.1., R1.5.2., and R1.5.3. Changed “website” and “web site” to “Web site.”	Errata

Standard Development Roadmap

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Development Steps Completed:

1. SAC Authorized for Development Feb 14 2006.
2.
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Description of Current Draft:

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Future Development Plan:

1.	TBD
2.	TBD
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A. Introduction

1. **Title:** **Documentation of Regional Reliability Organization Capacity Benefit Margin Methodologies**

2. **Number:** MOD-004-0

3. **Purpose:** To promote the consistent and uniform application of transmission Transfer Capability margins calculations, Capacity Benefit Margin (CBM) must be calculated in a consistent manner.

4. **Applicability:**

   4.1. Regional Reliability Organization

   4.2. Transmission Service Provider

5. **Effective Date:** ~~April 1, 2005~~TBD

B. Requirements

R1. Each Regional Reliability Organization, in conjunction with its members, shall jointly develop and document a Regional CBM methodology for all calculation horizons. ~~The Regional Reliability Organization's CBM methodology shall include each of the following ten items, and shall explain its use in determining CBM value. Other items that are Regional Reliability Organization specific or that are considered in each respective Regional Reliability Organization methodology shall also be explained along with their use in determining CBM values.~~

R1.1 A Transmission Provider who is completely within the RRO must comply with the RRO methodology.

R1.2 A Transmission Service Provider that crosses multiple Regional Reliability Organization boundaries may develop its own CBM methodology and shall get approval for its methodology from each of the respective RROs or from NERC

R1.3 Each CBM methodology shall address each of the items listed below

R1.3.1 Specify those TSPs which do not use CBM post that fact on their OASIS.

R1.3.2 Specify that the method used to determine its generation reliability requirements as the basis for CBM shall be consistent with the respective generation planning criteria.

R1.3.3 Specify the interval of calculation of the generation reliability requirement and associated CBM values.

R1.3.3.1 Require that the calculations must be verified at least annually.

R1.3.3.2 Require that the dates seasonal CBM values apply must be specified

R1.3.4 Require that generation unit outages considered in a Transmission Service Provider's CBM calculation be restricted to those units within the Transmission Service Provider's system.

~~**R1.4.**~~**R1.3.5** Require that CBM be preserved only on the Transmission Service Provider's System where the Load-Serving Entity's Load is located (i.e., CBM is an import quantity only).

R1.3.6 Describe the inclusion or exclusion rationale for generation resources of each Load- Serving Entity including those generation resources not directly connected to the Transmission Service Provider's system but serving Load-Serving Entity loads connected to the Transmission Service Provider's system. As a minimum the methodology must address the following:

R1.3.6.1 All generation directly connected to the transmission provider's system being used to serve load directly connected to that system will be considered in the CBM requirement determination.

~~R1.5.~~R1.3.6.2 The availability of generation not directly connected to the transmission provider's system being used to serve load directly connected to that system would be considered available per the terms under which it was arranged.

R1.3.7 Describe the inclusion or exclusion rationale for generation connected to the Transmission Service Provider's system but not obligated to serve Native/Network Load connected to the Transmission Service Provider's system. As a minimum the methodology must address the following:

R1.3.7.1 The following units shall be included in the CBM requirement determination because they are considered to be the installed generation capacity, committed to serve load, directly connected to the transmission system for which the CBM requirement is being determined.

R1.3.7.2 Generation directly connected to the transmission provider's system but not obligated to serve load directly connected to that system, will be incorporated into the CBM requirement determination as follows.

R1.3.7.2.1 Generation directly connected to the transmission provider's system, but committed to serve load on another system, will not be included in the CBM requirement determination for the transmission system to which the generator is directly connected.)

R1.3.7.2.2 For Generation directly connected to the TSP's system, but not committed to serve load on any system, the TSP will use the best information available to them to determine how these units should be considered in the CBM requirement determination. All assumptions made must be documented.

~~**R1.7.**~~**R1.3.8** Describe the formal process and rationale for the Regional Reliability Organization to grant any variances to individual Transmission Service Providers from the Regional Reliability Organization's CBM methodology.

R1.3.8.1 Any variances must be approved by NERC or its designee.

~~R1.8.~~R1.3.9 Specify the relationship of CBM to the generation reliability requirement and the allocation of the CBM values to the appropriate transmission facilities. The sum of the CBM values allocated to all interfaces shall not exceed that portion of the generation reliability requirement that is to be provided by outside resources.

~~R1.9.~~R1.3.10 Describe the inclusion or exclusion rationale for the loads of each Load-Serving Entity, including interruptible demands and buy-through contracts (type of service contract that offers the customer the option to be interrupted or to accept a higher rate for service under certain conditions).

R1.3.11 If[BDB1] CBM and TRM are used simultaneously in the ATC/AFC calculations explain how this is consistent with the Transmission Planning Criteria.

R1.3.12 Require[BDB2] that CBM be based on the required or recommended planning reserve. Describe how load-serving entities that are not meeting the Regional Reliability planning reserve requirements are addressed.

R1.3.13 Require that the appropriate entities will plan and reinforce the transmission system for the amount of CBM being preserved.

~~R2.3Describe the inclusion or exclusion rationale for generation reserve sharing arrangements in the CBM values.~~

R2. Each[BDB3] Regional Reliability Organization shall post the most recent version of the CBM methodology on a publicly accessible web site and each Transmission Service Provider shall post either a reference to the RROs posted methodology or the TSPs most recent approved version of the CBM methodology on its OASIS.

~~R3.The Regional Reliability Organization shall make the most recent version of the documentation of its CBM methodology available on a website accessible by NERC, the Regional Reliability Organizations, and transmission users.~~

C. Measures

M1. The Regional Reliability Organizations and Transmission Service Providers that apply CBM to their ATC/AFC calculation each have a documented CBM methodology that includes all of the items identified in MOD-004-1 Requirement 1 through MOD-004-1 Requirement 1.3.13.~~The Regional Reliability Organization's most recent CBM methodology documentation shall meet Reliability Standard MOD-004-0_R1~~.

M2. The Regional Reliability Organizations and Transmission Service Providers provides evidence that its CBM methodology is available on a publicly accessible web site in accordance with Reliability Standard MOD-004-1 Requirement 1.3.1 and Requirement 2.

~~M2.The Regional Reliability Organization's CBM methodology shall be available on a website accessible by NERC, the Regional Reliability Organizations, and transmission users.~~

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: NERC.

1.2. Compliance Monitoring Period and Reset Timeframe

The most recent version of CBM methodology documentation available on a website accessible by NERC, the Regional Reliability Organizations, and transmission users.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: The Regional Reliability Organization's and TSPs documented CBM methodology does not address one or two of the ~~ten~~ items required for documentation under Reliability Standard MOD-004-~~0~~1_R1 through R1.3.13.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: The Regional Reliability Organization's and TSPs documented CBM methodology does not address three or more of the ~~ten~~ items required for documentation under Reliability Standard MOD-004-~~0~~1_R1 through R1.3.13, or the Regional Reliability Organization does not have a documented CBM methodology available on a publicly accessible website in accordance with Reliability Standard MOD-004-~~0~~1_R2.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

Standard Development Roadmap

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A. Introduction

1. **Title:** **Procedure for Verifying Capacity Benefit Margin Values**

2. **Number:** MOD-005-~~0~~ 1

3. **Purpose:** To promote the consistent and uniform application of Transfer Capability calculations among transmission system users, the Regional Reliability Organizations need to review adherence to Regional methodologies for calculating Capacity Benefit Margin (CBM).

4. **Applicability:**

   4.1. Regional Reliability Organization

5. **Effective Date:** ~~April 1, 2005~~TBD

B. Requirements

R1. Each Regional Reliability Organization, in conjunction with its members, shall jointly develop and implement a procedure to review (at least annually) the CBM calculations. ~~and the resulting values of member Transmission Service Providers to ensure that they comply with the Regional Reliability Organization's CBM methodology.~~ The CBM review procedure shall ~~include~~[BDB1] ~~the following four requirements~~:

R1.1. Indicate the ~~frequency~~ interval is at least annual, under which the verification review shall be implemented.

R1.2. Require review of the process by which CBM values are updated, and their ~~frequency~~interval of update, to ensure that the most current CBM values are available to ~~transmission users~~stakeholders.

R1.3. Require review of the consistency of the Transmission Service Provider's CBM components with its published planning criteria. A CBM value is considered consistent with published planning criteria if the same components that comprise CBM are addressed in the planning criteria. The methodology used to determine and apply CBM does not have to involve the same mechanics as the planning process, but the same uncertainties must be considered and any simplifying assumptions explained. The procedure must specify how the consistency would be verified.

R1.3.1. Require verification that the appropriate entities are planning and reinforcing the transmission system for the amount of CBM being preserved. The procedure must specify how the verification would be determined. Transmission service providers must also perform this verification and report on the findings as specified below.

R1.4. Require CBM values to be periodically updated at least annually~~(at least annually)~~ and available to the Regional Reliability Organizations, NERC, and ~~transmission users~~stakeholders.

R2. The documentation of the Regional CBM procedure shall be available to NERC on request (within 30 days). ~~Each Regional Reliability Organization shall document its CBM procedure and shall make its CBM review procedure available to NERC on request (within 30 calendar days).~~

R3. Documentation of the results of the most current implementation of the procedure shall be sent to NERC within 30 days of completion.~~The Regional Reliability Organization shall provide~~

~~documentation of the results of the most current implementation of its CBM review procedure to NERC on request (within 30 calendar days).~~

C. Measures

M1. The Regional Reliability Organization's written procedure for the performance of periodic reviews of Regional CBM calculations shall comply with Reliability Standard MOD-005-1_R1.

M2. The Regional Reliability Organization shall have documentation of the results of its periodic reviews of CBM calculations, in accordance with Reliability Standard MOD-005-0_R2 and MOD-005-0_R3.

M3. The Regional Reliability Organization shall have evidence that it provided documentation of its CBM review procedure and the results of the most current implementation of the procedure to NERC as requested (within 30 calendar days).

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: NERC.

1.2. Compliance Monitoring Period and Reset Timeframe

The documentation of the Regional Reliability Organization's CBM review procedure shall be available to NERC on request (within 30 calendar days). Documentation of the results of the most current implementation of the review procedure shall be available to NERC on request (within 30 calendar days).

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: The Regional Reliability Organization did not perform an annual review of all Transmission Service Providers within its Region for consistency with the Regional CBM methodology.

2.3. Level 3: Not applicable.

2.4. Level 4: The Regional Reliability Organization does not have a procedure for performing a CBM methodology consistency review of all Transmission Service Providers within its Region, or has not performed any annual reviews.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

Standard Development Roadmap

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A. Introduction

1. **Title:** **Documentation and Content of Each Regional Transmission Reliability Margin Methodology**

2. **Number:** MOD-008-~~0~~1

3. **Purpose:** To promote the consistent application of transmission Transfer Capability margin calculations among Transmission Service Providers and Transmission Owners, each Regional Reliability Organization shall develop a methodology for calculating Transmission Reliability Margin (TRM). This methodology shall comply with the NERC definition for TRM, the NERC Reliability Standards, and applicable Regional criteria.

4. **Applicability:**

   4.1. Regional Reliability Organization

5. **Effective Date:** ~~April 1, 2005~~TBD

B. Requirements

R1. Each Regional Reliability Organization, in conjunction with its members, shall jointly develop and document a Regional TRM methodology. This methodology shall be available to NERC, the Regions, and the transmission users in the electricity market. If a Regional Reliability Organizations members TRM values are determined by a Regional Transmission Organization (RTO) or Independent System Operator (ISO), then a jointly developed regional methodology is not required for those members. Regional Reliability Organizations members not covered by an RTO or ISO would be required to have a regional methodology. ~~The This Region's TRM methodology shall specify or describe each of the following five items, and shall explain its use, if any, in determining TRM values. Other items that are Region-specific or that are considered in each respective Regional methodology shall also be explained along with their use in determining TRM values.~~

R2. Each TRM methodology shall address each of the items listed below

~~R1.1.~~R2.1. Specify the update ~~frequency~~interval of TRM calculations.

R2.1.1. Require that calculations be verified at least annually if determined to be required

R2.1.2. Require that dates that seasonal TRM values apply must be specified

~~R1.2.~~R2.2. Specify how TRM values are incorporated into Available Transfer Capability or Available Flowgate Capability calculations.

~~R1.3.~~R2.3. Specify the uncertainties accounted for in TRM and the methods used to determine their impacts on the TRM values. The following components of uncertainty, if applied, shall be accounted for solely in TRM and not CBM: ~~Any component of uncertainty, other than those identified in MOD-008-0_R1.3.1 through MOD-008-0_R1.3.7, shall benefit the interconnected transmission systems as a whole before they shall be permitted to be included in TRM calculations. The components of uncertainty identified in MOD-008-0_R1.3.1 through MOD-008-0_R1.3.7, if applied, shall be accounted for solely in TRM and not CBM.~~

R2.3.1. Aggregate Load forecast error (not included in determining generation reliability requirements).

R2.3.2. Load distribution error.

R2.3.3. Variations in facility Loadings due to balancing of generation within a Balancing Authority Area.

R2.3.4. Forecast uncertainty in transmission system topology.

R2.3.5. Allowances for parallel path (loop flow) impacts.

R2.3.6. Allowances for simultaneous path interactions.

R2.3.7. Variations in generation dispatch.

R2.3.8. Short-term operator response (operating reserve actions not exceeding a 59-minute window).

R2.3.9. Any additional components of uncertainty shall benefit the interconnected transmission systems, as a whole, before they shall be permitted to be included in TRM calculations.

R2.3.10. Additional detail on how variations in generation dispatch are handled from intermittent generation sources such as wind and hydro, need to be provided.

~~R1.4.~~R2.4. Describe the conditions, if any, under which TRM may be available to the market as Non-Firm Transmission Service.

~~R1.5.~~R2.5. Describe the formal process for the granting of ~~Regional Reliability Organization to grant~~ any variances to individual Transmission Service Providers from the Regional TRM methodology.

R2.5.1. Any variances must also be approved by NERC or its designate

R2.6. Describe the methodology and conditions thereof that are used to reflect if TRM is reduced for the operating horizon.

R2.7. Explain how the simultaneous application of CBM and TRM amounts being implemented in the ATC calculations are being taken into consideration during the planning process.

R2.8. Specify TRM methodologies and values must be consistent with the approved planning criteria.

R2.8.1. Require that the appropriate entities will plan and reinforce the transmission system for the amount of TRM being preserved. The methodology must specify how the verification of the consistency would be determined.

R2.9. Each TRM methodology shall address each of the items above and shall explain its use, if any, in determining TRM values. Other items that are entity specific or that are considered in each respective methodology shall also be explained along with their use in determining TRM values.

~~R2.~~R3. The Regional Reliability Organization shall make its most recent version of the documentation of its TRM methodology available on a publicly accessible web site. ~~accessible by NERC, the Regional Reliability Organizations, and transmission users.~~

C. Measures

M1. The Regional Reliability Organization's most recent version of the documentation of its TRM methodology is available on a publicly accessible website. ~~accessible by NERC, the Regional Reliability Organizations, and transmission users.~~

M2. The Regional Reliability Organization's most recent posted version of the documentation of its TRM contains all items in Reliability Standard MOD-008-~~0~~1_~~R1~~R2.1 through 2.8.2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: NERC.

1.2. Compliance Monitoring Period and Reset Timeframe

Each Regional Reliability Organization shall report compliance and violations to NERC via the NERC Compliance Reporting process.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: The Regional Reliability Organization's documented TRM methodology does not address one of the ~~five~~ items required for documentation under Reliability Standard MOD-008-0_~~R1~~R2.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: The Regional Reliability Organization's documented TRM methodology does not address two or more of the five items required for documentation under Reliability Standard MOD-008-0_~~R1~~R2 or the Regional Reliability Organization does not have a documented TRM methodology available on a publicly accessible website in accordance with Reliability Standard MOD-008-1_R3.

~~**Or**~~

~~The Regional Reliability Organization does not have a documented TRM methodology.~~

E. Regional Differences

1. None identified.

Version History

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A. Introduction

1. **Title:** **Procedure for Verifying Transmission Reliability Margin Values**

2. **Number:** MOD-009-~~0~~ 1

3. **Purpose:** To promote the consistent application of transmission Transfer Capability margin calculations among Transmission System Providers and Transmission Owners.

4. **Applicability:**

   4.1. Regional Reliability Organization

5. **Effective Date:** ~~April 1, 2005~~TBD

B. Requirements

R1. Each Regional Reliability Organization, in conjunction with its members, shall develop and implement a procedure to review Transmission Reliability Margin (TRM) calculations and resulting values of member Transmission Service Providers to ensure they comply with the Regional TRM methodology, and are periodically updated and available to transmission users. ~~This procedure shall include the following four required elements:~~

R1.1. The Regional Reliability Organization must review and approve the TRM methodology for all calculation horizons. The Regional Reliability Organization is responsible for ensuring that TRM calculations are consistent with the individual Transmission Owners planning criteria

R2. Each TRM methodology shall address each of the items listed below:

~~**R1.1.**~~**R2.1.** Indicate the ~~frequency~~interval is at least annual, under which the verification review shall be implemented.

~~**R1.2.**~~**R2.2.** Require review of the process by which TRM values are updated, and their ~~frequency~~interval of update, to ensure that the most current TRM values are available to ~~transmission users~~stakeholders.

~~**R1.3.**~~**R2.3.** Require review of the consistency of the Transmission Service Provider's or Transmission Owners TRM components with its published planning criteria. A TRM value is considered consistent with published planning criteria if the same components that comprise TRM are also addressed in the planning criteria. The methodology used to determine and apply TRM does not have to involve the same mechanics as the planning process, but the same uncertainties must be considered and any simplifying assumption explained. The review process used by a transmission service provider or transmission owner also needs to be documented.

R3.2.1. Explain how the simultaneous application of CBM and TRM amounts being implemented in the ATC calculations are being taken into consideration during the planning process

R2.4. TRM methodologies and values must be consistent with the applicable planning criteria

R4.2.1. The methodology must specify how the verification of the consistency would be determined

~~**R1.4.** Require TRM values to be periodically updated (at least prior to each season — winter, spring, summer, and fall), as necessary, and made available to the Regional Reliability Organizations, NERC, and transmission users.~~

~~**R2.**~~**R3.** The documentation of the regional TRM procedure shall be available to NERC on request (within 30 days). Documentation of the results of the most current implementation of the procedure shall be available to NERC within 30 days of completion.~~The Regional Reliability Organization shall make documentation of its Regional TRM review procedure available to NERC on request (within 30 calendar days).~~

~~**R3.**~~**R4.** Documentation of the results of the most current regional reviews shall be provided to NERC within 30 days of completion.~~The Regional Reliability Organization shall make documentation of the results of the most current implementation of its TRM review procedure available to NERC on request (within 30 calendar days).~~

R5. Require TRM values to be verified at least annually and made available on a publicly accessible website.

C. Measures

M1. The Regional Reliability Organization shall have evidence that it provided to NERC upon request (within 30 calendar days) a copy of its written procedure developed for the performance of periodic reviews of Regional TRM calculations.

M2. The Regional Reliability Organization shall have evidence it provided to NERC on request (within 30 calendar days) documentation of the results of the most current implementation of its TRM review procedure.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: NERC.

1.2. Compliance Monitoring Period and Reset Timeframe

Each Regional Reliability Organization shall report compliance and violations to NERC via the NERC Compliance Reporting process.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: The Regional Reliability Organization did not perform an annual review of all Transmission Service Providers within its Region for consistency with its Regional TRM methodology.

2.3. Level 3: Not applicable.

2.4. Level 4: The Regional Reliability Organization does not have a procedure for performing a TRM methodology consistency review of all Transmission Service Providers within its Region, or has not performed any such annual reviews.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New