NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Joint NERC/NAESB ATCT Standards Drafting Team Meeting

Marriott Memphis Downtown
250 Main Street, Memphis TN 38103
Phone 901-527-7300

March 1, 2007: noon[1] – 5:00 pm (Central Time)
Conference call phone number 1(732)694-2061 Conference code is 1165030107 #
Meeting number: 715 910 961 Meeting password: 123456
https://nerc.webex.com

March 2, 2007: 8:00 am – noon (Central Time)
Conference call phone number 1(732)694-2061 Conference code is 1165030207 #
Meeting number: 711 562 845 Meeting password: 123456
https://nerc.webex.com

Agenda

1) Administration

a) Welcome and Introductions — Larry Middleton
Chairman Middleton will lead the welcome of the ATCT drafting team members and guests. NERC ATCT Drafting Team Roster (**Attachment 1a**)

b) Antitrust Compliance Guidelines — Bill Lohrman (**Attachment 1b**)
Bill Lohrman will review the NERC Antitrust Compliance Guidelines provided in Attachment 1b. 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.

c) Review of Agenda — L. Middleton
Chairman Middleton will review the objectives of the meeting.

d) Approval of meeting minutes — B. Lohrman
The drafting team will be asked to approve the minutes (**Attachment 1d to be sent via separate email**) of the February 7-8, 2007 meeting.

e) Review of NAESB ATC Group minutes for 1/30 and 2/9 (**Attachments 1e1 and 1e2**)

[1] Formal meeting to start after working lunch at noon

2) MOD-001 – 1

a) The drafting team will review the status of MOD-001-1 and the tentative schedule for reviewing comments. – B. Lohrman / L. Middleton

b) Discussion of FERC Order 890 (http://www.ferc.gov/whats-new/comm-meet/2007/021507/E-1.pdf) and establishment of timeline. (http://www.ferc.gov/industries/electric/indus-act/oatt-reform/sum-compl-filing.asp) to complete items set forth in the Order (**Attachment 2b**) within the time frame established in the Order. – L. Middleton / K. York

c) Review of Joint NERC / NAESB procedure – L. Middleton / K. York
The NERC-NAESB Procedure for Joint Development and Coordination (**Attachment 2c1**) was established in order to guide joint development of standards and business practices when the reliability and business practice components are intricately entwined within a proposed standard. This procedure has been approved for implementation by the Standards Committee, NERC Board of Trustees and the NAESB Board.

The supplement (**Attachment 2c2**) to the NERC-NAESB Procedure for Joint Standards Development and Coordination and the Supplement to NERC-NAESB Procedure for Joint Standards Development and Coordination is intended to aid the two organizations and their stakeholders in implementing the procedure.

3) MOD-003-1

a) The drafting team will consider comments from NAESB regarding the draft of the proposed MOD-003-1 (**Attachment 3a**).

b) During its last meeting the NERC ATCT drafting team agreed that this MOD should be a NAESB business practice. (**Attachment 3b**)

c) The joint team will discuss the requirements for recommending this change. – L. Kennedy / K. York

4) TRM – L. Middleton

a) Chairman Middleton will lead the drafting team in a review of the changes from the last drafting team meeting (**Attachments 4a1 and 4a2**) with respect to the requirements of Order 890.

5) ETC Requirements – L. Middleton

a) Chairman Middleton will lead the drafting team in developing proposed requirements for Existing Transmission Commitments requirements with respect to the requirements of Order 890.

(1) Strawman bullet items could be
- (a) Treatment of firm and non-firm
- (b) Documentation / transparency issues
- (c) Pending transmission commitments/Good Faith Requests:
- (d) Roll-over rights
- (e) Network Response vs Rated System Path
- (f) Counterflows
- (g) Network Native Loads

(h) Existing transmission contracts (Firm Transmission Reservations for Energy Transactions)
(i) Interruptible demands
(j) Ancillary services
(k) Reserving transfer capability over multiple paths to secure capacity for a future undefined resource or purchase
(l) Impact of parallel flow from 3rd party transactions
(m) Information to be provided: The following lists the types of assumptions and data that could be used in support of the determination of Committed Uses. Transmission Providers should make available the information used in their calculation of ATC values.
  (i) Far-Term Environment (>1 year)
    1. Load forecast
    2. Load forecast error (range)
    3. Standard for serving load
    4. Breakdown of use by path
    5. Breakdown of use by Time of Use period
    6. Hydro and temperature forecasts
    7. DSM, interruptible load assumptions
    8. Redundancy of reserved paths
    9. Resource outage standards (G-1? G-2?)
    10. Resource assumptions (high/low hydro...)
    11. Forecasted outages
    12. Unit deratings
    13. Resource dispatch assumptions
    14. Purchases or sales to external parties
    15. Wheeling contracts, including listings of Points of Receipt, Points of
    16. Delivery, and associated transmission demands at each point.
  (ii) Near-Term Environment (<1 month)
    1. Standard for probability of serving load
    2. Load forecasts (range of temperatures, hydro forecast, etc.)
    3. Resource outage standards (G-1? G-2?)
    4. Forecasts of generation
    5. Short-term wheeling arrangements, including listings of Points of Receipt,
    6. Points of Delivery, and associated transmission demands at each point.
    7. Purchases and sales with external parties.

6) CBM – L. Middleton

a) Chairman Middleton will lead the drafting team in developing proposed changes to the CBM standards The team will develop criteria for revising the standards with respect to the requirements of Order 890.
  (1) Strawman bullet items and their assignments
    (a) Emergency actions – Kiko Barredo
    (b) Double counting – Ray Kershaw / Chuck Falls / Ross
    (c) Minority paper issues – Dennis Kimm
    (d) Source / Sink requirements – Barbara Rehman
    (e) Calculation methods – Nate Schweighart / Ray Kershaw
      (i) Justification

(f) Reciprocal agreements / Reserve sharing – Jerry Smith
(g) Replacement reserves – t.b.d.
(h) Import of ancillary services – t.b.d.
(i) Generation outages – Kiko Barredo
(j) Generation components to be included – t.b.d.
(k) Relationship to Resource Adequacy SAR/Standard – t.b.d.
(l) Review issues from NERC CBM SAR – Barbara Rehman
(m) Update on the NAESB CBM activities – which portions should be business practices and which should be reliability standards – Narinder Saini
(n) Review of issues from NERC CBM whitepaper – Chuck Falls
(o) Documentation / transparency issues – t.b.d.
(p) Cataloging of various uses and interpretations of CBM – drafting team
  (i) How should they be differentiated?
  (ii) Should CBM be an explicit reservation?
  (iii) How and if it would be made a requirement
  (iv) Would it be source to sink or partial path?
  (v) How it might impact systems that use CBM for resource adequacy?
(q) Whether there should be a reciprocal agreement for the use of CBM. – drafting team
(r) Should CBM be based on required or recommended planning reserve? – drafting team
(s) Whether entities should plan and reinforce their systems for the amount of CBM being reserved. – drafting team
(t) How would RRO (and NERC?) approve CBM/TRM methodologies? – drafting team
(u) How should TRM be made consistent with applicable planning criteria? – drafting team

7) FAC 12 / FAC 13 – L. Middleton

a) Chairman Middleton will lead the drafting team in a review of the changes necessary to begin work on the FAC-12 and FAC-13 standards (**Attachments 7a1 and 7a2**).
  i) Documentation / transparency issues
  ii) List of TTC and TFC items removed from MOD-001-1
    (a) Bill Lohrman(items from Sept onward) (**Attachment 7iia**)
    (b) Larry Middle (items from March onward) (**Attachment 7iib – separate email**)
  iii) Review of similarities/differences between Transfer Capability (TC) and Total Transfer Capability (TTC)
  iv) Relationship between FAC 12/13 and other FAC standards (e.g. FAC 8&9)
    (a) Narinder Saini
    (b) Barbara Rehman
  v) Applicability
  vi) Review of requirements for TTC and TFC
    (a) Laura Lee
    (b) Kiko Barredo
    (c) Nate Schweighart

8) Review of meeting schedules – L. Middleton / K. York

a) March 13, 2007 8:00 am to 5pm and March 14, 2007 8:00am to noon at the Salt River Project operations center located at 6504 E Thomas Rd, Scottsdale, AZ 85281.
b) Joint NERC / NAESB meeting April 24, 2007 10:00 am – 5:00pm and April 25, 2007 9:00 am – 5:00 pm (Central Time)

Adjourn

Attachment 1a

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

Chairman	Larry W. Middleton Transmission Asset Management	Midwest ISO, Inc. 701 City Center Drive Carmel, Indiana 46032	(317) 249-5447 (317) 249-5703 Fx lmiddleton@ midwestiso.org
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	D. DuShaune Carter, P.E. Operations Planning Engineer	Southern Company Services, Inc. 600 North 18th Street PCC Corp-Hq Birmingham, Alabama 35291-2625	(205) 257-5775 (205) 257-6663 Fx ddcarter@southernco .com
	E. Nick Henery Director of Reliability Standards and Compliance	American Public Power Association 2301 M Street, N.W. Washington, DC 20037-1484	(202) 467-2985 NHenery@APPAnet. org
	Raymond K. Kershaw Transmission Operations Engineer	International Transmission Company 39500 Orchard Hill Place Suite 205 Novi, Michigan 48375	(248) 444-1209 (248) 374-7137 Fx rkershaw@ itctransco.com
	Dennis Kimm, Jr. Senior Transmission Engineer	MidAmerican Energy Co. 4299 NW Urbandale Drive Urbandale, Iowa 50322	(515) 252-6737 (515) 281-2355 Fx ddkimm@ midamerican.com
	Ross Kovacs Trans. Strategic Coordinator	Georgia Transmission Corporation 2100 E. Exchange Place Tucker, Georgia 30085	(770) 270-7857 ross.kovacs@ gatrans.com
	Laura Lee Senior Engineer	Duke Energy System Operations 526 South Church Street Charlotte, NC 28202	704-382-3625 llee@duke- energy.com
	Cheryl Mendrala Tariff and Contract Administrator	ISO New England, Inc. One Sullivan Road Holyoke, Massachusetts 01040	(413) 535-4184 (413) 535-4399 Fx cmendrala@ iso-ne.com
	Rob Morasco Engineer	PJM Interconnection, L.L.C. 955 Jefferson Avenue Norristown, Pennsylvania 19403	(610) 635-3452 morasr@pjm.com

	Narinder K. Saini Policy Consultant	Entergy Services, Inc. 5201 W. Barraque Pine Bluff, Arkansas 71603	(870) 543-5420 (870) 541-4528 Fx nsaini@ entergy.com
	Matthew E Schull Manager, Power Supply	North Carolina Municipal Power Agency 1427 Meadow Wood Blvd Raleigh, North Carolina 27604	(919) 760-6312 (919) 760-6050 Fx mschull@ electricities.org
	Jerry W. Smith	Arizona Public Service Co. Mail Station 2260 PO Box 53999 Phoenix, Arizona 85072-3999	(602) 250-1155 jerry.smith@ aps.com
	Nathan Schweighart	Tennessee Valley Authority 1101 Market Street MR-5G Chattanooga, Tennessee 37402-2801	(423) 751-4365 (423) 751-3453 Fx naschweighart@ tva.gov
	W. Shannon Black Sr. Regulatory and Contract Specialist	SMUD 6301 S Street Sacramento, CA	916-732-5734 sblack@smud.org
NERC Staff Coordinator	William W. Lohrman Managing Director	Prague Power, LLC 31 Maple Street, Suite 102 Bernardsville, New Jersey 07924	(908) 630-0289 wwlohrman@ praguepower.com

Attachment 1b

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

Princeton Forrestal Village, 116-390 Village Boulevard, Princeton, New Jersey 08540-5731

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.

Approved by NERC Board of Trustees, June 14, 2002
Technical revisions, May 13, 2005

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.

Attachment 1e1

North American Energy Standards Board

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Home Page: www.naesb.org

TO: NAESB Wholesale Electric Quadrant Business Practices Subcommittee (BPS), Electronic Scheduling Subcommittee (ESS), Information Technology Subcommittee (ITS), and Interested Industry Participants

FROM: Laura Kennedy, Meeting/Project Manager, NAESB

RE: Draft Minutes from the NAESB Joint BPS/ESS/ITS Conference Call Meeting – January 30, 2007

DATE: February 22, 2007

NAESB WHOLESALE ELECTRIC QUADRANT JOINT BPS/ESS/ITS
JANUARY 30, 2007 CONFERENCE CALL
10:00 AM TO 3:00 PM CENTRAL
DRAFT MINUTES

1. Welcome

Ms. York opened the meeting and welcomed the meeting participants. Ms. Kennedy read the antitrust guidelines. Mr. Saini moved, seconded by Mr. Eckelkamp, to adopt the agenda as drafted. There was no objection to the motion. The subcommittee reviewed the draft minutes from the January 8, 2007 conference call. In addition to a few grammatical changes, Mr. Saini suggested modifying the first paragraph on page two to add language to further clarify his statements. Mr. Saini moved, seconded by Mr. Lohrman, to adopt the minutes from the January 8, 2007 conference call as revised. The motion passed without objection. The final minutes from the January 8, 2007 conference call are posted on the NAESB website at: Final Minutes.

2. Update on NERC ATC Drafting Team Progress (MOD001-1) and additional MODs

MOD001-1: Mr. Lohrman stated that the NERC ATC Drafting Team submitted the draft of revised MOD001-1 to the NAESB ESS/ITS and BPS for informal comment purposes. Mr. Lohrman stated that the NERC ATC Drafting Team made modifications to MOD001-1 based on the comments of the NAESB subcommittees including acknowledgement that posting requirements would be included in the complementary NAESB standards. The NERC ATC Drafting Team also forwarded the draft MOD001-1 to Ms. Long of the NERC staff for review. Ms. Long responded with several formatting suggestions that the NERC ATC Drafting Team also addressed during the last meeting. The NERC ATC Drafting Team is now waiting to hear back from Ms. Long that no further modifications are needed so that the document can be posted for comment.

Ms. York asked if NERC would present MOD001-1 to the NAESB team one more time before it is officially posted for comment. Mr. Saini agreed that it should be reviewed by the NAESB team one more time. Mr. Lohrman stated that it is the expectation that MOD001-1 will be posted for comment on February 15 so if the NAESB ESS/ITS and BPS can review for any last minutes comments prior to that time there should not be a problem with one more review. Mr. Lohrman noted that the NERC ATC Drafting Team did not plan on modifying the document unless the NAESB team finds significant inconsistencies or problems with the language. Mr. Pritchard noted that the NAESB ESS/ITS and BPS have a scheduled joint conference call on February 9 and could review the document during that time. Mr. Lohrman stated he would forward the document to the NAESB office for posting for the February 9 call.

MOD002: Ms. York stated that during the last meeting of the NERC ATC Drafting Team, the participants agreed to move all of the requirements in MOD002 to MOD001-1. The revised

MOD002 is posted in redline format as a work paper for this meeting: http://www.naesb.org/pdf2/weq_atc_afc013007w3.pdf. The NERC ATC Drafting Team plans to delete MOD002 upon the approval of MOD001-1. Mr. Lohrman stated the rationale behind removing MOD002 was due to the NERC reliability standards including compliance requirements in the standards themselves.

MOD003: The subcommittee next reviewed the latest draft of MOD003 posted in redline format as a work paper for this meeting: http://www.naesb.org/pdf2/weq_atc_afc013007w4.pdf. The subcommittee requested Mr. Lohrman to send the document in native format so that comments could be inserted within the document. The subcommittee added comments to the native redlined document for review by the NERC ATC Drafting Team.

Mr. Pritchard stated that the Introduction Section states that the Purpose states "To promote the communication of Transmission Service Provider calculation methodologies and values…" and that communication is a function of NAESB business practices. Mr. Pritchard stated that the requirements set forth in MOD003 should be developed by NAESB instead of NERC. He suggested that the NERC ATC Drafting Team retire MOD003 similarly in the way they plan to do for MOD002 and suggest that the NAESB ESS/ITS and BPS develop NAESB business practices to cover the same issues. Mr. Lohrman stated that in order to conduct reliability control there needs to be communication and coordination so the standards should stay at NERC. Mr. Pritchard stated that the requirements in the draft of MOD003 will require posting on OASIS; OASIS posting requirements are developed by NAESB. Mr. Saini agreed with Mr. Pritchard and stated that he championed the same position at the NERC ATC Drafting Team meeting.

Mr. Pritchard stated that in order to make the determination of whether the standards should be NERC reliability standards or NAESB business practice standards is to answer the question: If the requirements were not met would the system be less reliable? Mr. Lohrman stated that the system would be less reliable because transmission could be oversold. Mr. Pritchard stated that the language in MOD003 does not set forth what will happen if the procedures are not done correctly, but sets forth the communications of the calculation of methodologies and values among the Transmission Customers of the Transmission Service Provider. Mr. Eckelkamp and Mr. Saini supported Mr. Pritchard's position.

Mr. Lohrman suggested that the NAESB ESS/ITS and BPS present their comments on MOD003 in a joint meeting with the NERC ATC Drafting Team. The subcommittee agreed and decided to review the rest of MOD003 to include any additional comments.

For the Purpose section, the subcommittee added the following comments:

> "NAESB comment that this should be business practices; it only addresses and penalizes failures to communicate. Communication is typically a NAESB business practice development area. Failure to communicate does not affect reliability of the system."
>
> "Comment: talking about values that go into the calculation or the actual calculated ATC/AFC value itself? Need clarification on this item."

Mr. Pritchard added that the person familiar with the methodology will not likely be the person who is familiar with the actual values.

For the Applicability section, it was mentioned that some entities do not have OASIS. Those entities are non-jurisdictional as far as requirements to have an OASIS, but are jurisdictional for reliability purposes. The subcommittee's comment on the Applicability statement: "Are there non-jurisdictional entities that 4.1.1. would apply to?"

Mr. Lohrman stated that the Risk Factors were removed at the direction of the FERC.

For R1, Mr. Pritchard stated that he did not understand why there was a requirement to post the phone number and e-mail address of a contact person on OASIS when the NERC MOD003-1 standard as drafted also requires an OASIS methodology for submitting questions. This creates two methods for contacting the Transmission Service Provider. The draft standard also puts requirements and measures around the responses to the OASIS submissions. Mr. Lohrman stated that the NERC ATC Drafting Team added the phone and e-mail requirement for simple questions. Mr. Pritchard added that Duke Energy has a number of people that might be involved in the actual calculation of ATC, but the person changes from one shift to the next.

Mr. Pritchard added that there is no performance measure in the draft document to require that the person listed respond to the phone call or e-mail. Mr. Pritchard suggested that NERC eliminate the two channels for contact. For R2, Mr. Pritchard suggested changing the word "field" to "form".

Based on the discussion, the following comments were added to the document:

> "The person who knows the methodology is not necessarily the same individual who contributes to the day to day ATC/AFC posting; posting of one e-mail address will not necessarily be sufficient for answering all questions.
>
> If expected to post new names with shift changes, will be administrative burden for TP.
>
> Need clarification whether standard would allow submission of question through e-mail as provided in R1 or only through OASIS posting as set forth in R2
>
> If questions are accepted through e-mail are those also required to be posted on OASIS?"

Mr. Pritchard noted that the name and contact information of the Compliance Officer is now required to be posted. The Compliance Officer can easily follow up on any questions from Transmission Customers regarding what should be posted on OASIS.

For R3, the subcommittee added the following comments:

> "If NAESB develops template for posting and is not referenced in the NERC standard, does that mean this requirement lends itself to being adopted by NAESB?
>
> R3 treats all queries equally. All queries must be responded to within a week. Some may take longer to respond to due to the nature of the query. Limitation of 1 week appears to be arbitrary. It is the understanding of the NAESB subcommittee that R3 only addresses queries submitted under R2."

Next, the subcommittee reviewed the Compliance measures in the draft of MOD003-1. Mr. Pritchard stated that the requirements for monitoring and penalizing companies for failure to do things that are business practice related move into the NAESB business practices area. He added that the Violation Security Levels are also arbitrary when applied to an instance where a Transmission Provider receives one question in a year and does not respond within five days, then the Transmission Provider would be at a Violation Level of Severe. He added that there is nothing to prevent a Transmission Customer from flooding the queue with questions that would require a great deal of additional work on the part of the Transmission Provider. Mr. Pritchard suggested that the NERC ATC Drafting Team revise the language to state clearly what the Transmission Provider should respond to and then ask NAESB to develop a business practice standard around the requirement. Based on the discussion, the following comments were added to the document:

"Suggestion that a threshold needs to be established for those entities that have low numbers of inquiries.

There is no real definition what constitutes a valid query. There is potential for queue flooding with spurious queries."

The draft of MOD003 that includes the comments from the NAESB subcommittees is posted as an attachment to these minutes at Draft NERC MOD003-1 with NAESB Comments on 1/30/07.

3. R05004A Item 1A (where the allocation of flowgate capability based on historical Network Native Load impacts the evaluation of transmission service requests, requiring the posting of those allocation values in conjunction with queries of service offerings on OASIS)

Mr. Saini stated that business practices are needed to indicate where the information on the allocation of values is posted. Mr. Middleton stated that MISO and PJM currently post this information as part of their Joint Operating Agreements.

After further discussion, Mr. Middleton volunteered to provide an excerpt of the MISO/PJM Joint Operating Agreement relevant to this agenda item for the February 9 conference call.

4. R05004A Item 3E (business practices for calculation and frequency of posting ATC calculation)

Ms. Rehman stated that during the last meeting it was decided the NAESB would determine the posting periods and the timing for updating information would be a NERC standard. Mr. Lohrman stated that NERC will develop not the timing for posting of ATC calculation but the frequency of the posting of the ATC calculation.

Mr. Lohrman stated that the NERC ATC Drafting Team made changes to data exchange language based on comments from Mr. Wood, but the timing will be in accordance with the NAESB business practice. Ms. Rehman stated that the ATC calculation methodology is not specific for when to exchange data. Mr. Lohrman stated much of the information required for calculation of ATC is related to TTC and FERC asked NERC to move all of the TTC calculation and information requirements to FAC 12 and FAC 13. The adjustments will be set forth in the FAC standards. The ATC requirements only include the calculation while the requirements and communication is going to take place in FAC 12 and 13. Ms. Rehman stated that some organizations calculate ATC first and then derive TTC from that calculation. Mr. Lohrman stated that methodology is not included in the draft NERC standards.

The subcommittee reviewed the document posted as a work paper for this meeting: FERC and NERC Minimum Current Requirements Chart for Calculations and Frequency of Posting ATC/TTC and made additions based on the latest draft of NERC MOD001-1.

For Constrained and Unconstrained Paths, a requirement was added to develop business practices surrounding the timing requirements for reposting AFC on OASIS. (Reference to NERC MOD001 Flowgate AFC data (3.1.5.9 – 3.1.5.12)) For Constrained and Unconstrained Paths, a requirement was added to develop business practices surrounding the posting of methodology to calculate ATC and AFC on OASIS. (Reference to OATT Section 15.2, OATT Attachment C, and NERC MOD001 R7).

The revised Minimum Current Requirements Chart for Calculations and Frequency of Posting ATC/TTC is posted as an attachment to these minutes: http://www.naesb.org/pdf2/weq_atc_afc013007a1.doc.

5. Other Business/Next Steps/Future Meetings

The subcommittee has the following meetings/conference calls scheduled:

- **February 9, 2007:** Conference call of the NAESB ESS/ITS and BPS from 10:00 AM to 3:00 PM Central. The agenda for this call will include:
  - Language from Mr. Middleton to address Item 1A (MISO PJM JOA Language)
  - Ms. Rehman volunteered to draft language for Posting Requirements for Item 3E.
  - Discussion of the CBM items included in Request No. R05004A
- **March 1-2, 2007:** The NAESB ESS/ITS and BPS agreed to schedule this meeting as a joint meeting with the NERC ATC Drafting Team. Mr. Lohrman stated that the meeting will be in either Memphis, TN or Nashville, TN. The meeting will be from 12:00 AM to 5:00 PM on March 1 and from 8:00 AM to 12:00 PM on March 2. NERC is the host of this meeting and will provide the agenda, work papers, and meeting administration for this meeting. The agenda for this meeting will include:
  - NAESB Comments on MOD003
  - CBM, TRM
  - FAC12 and FAC 13
- **March 7, 2007:** Conference call of the NAESB ESS/ITS and BPS from 10:00 AM to 3:00 PM Central
- **April 17, 2007:** Meeting of the NAESB ESS/ITS and BPS in Houston, Texas hosted by NAESB. Meeting times are 10:00 AM to 4:00 PM Central.
- **April 24-25, 2007**: Joint meeting of the NAESB ESS/ITS and BPS and NERC ATC Drafting Team hosted by NAESB in Houston, Texas. The meeting times are 10:00 AM to 5:00 PM Central on April 24 and from 9:00 AM to 5:00 PM Central on April 25. It is the expectation that during this meeting the committees will review comments on MOD001.

6. Adjourn

Mr. Pritchard moved, seconded by Mr. Saini to adjourn. The meeting adjourned at 2:45 PM Central.

7. Attendance

Name	Organization
Mark Anderson	Seminole Electric
George Behr	Energy Services Group
Rebecca Birdall	BPA
Blaine Earhart	Basin Electric
Jim Eckelkamp	Progress Energy
Laura Kennedy	NAESB
Bill Lohrman	NERC
Larry Middleton	MISO
Marjorie Perlman	Energy East
Alan Pritchard	Duke Energy
Barbara Rehman	BPA

Narinder Saini	Entergy
Martin Summe	ElectriCities
Kathy York	Tennessee Valley Authority

Attachment 1e2

North American Energy Standards Board

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Home Page: www.naesb.org

TO: NAESB Wholesale Electric Quadrant Business Practices Subcommittee (BPS), Electronic Scheduling Subcommittee (ESS), Information Technology Subcommittee (ITS), and Interested Industry Participants

FROM: Laura Kennedy, Meeting/Project Manager, NAESB

RE: Draft Minutes from the NAESB Joint BPS/ESS/ITS Conference Call Meeting – February 9, 2007

DATE: February 22, 2007

NAESB WHOLESALE ELECTRIC QUADRANT JOINT BPS/ESS/ITS
FEBRUARY 9, 2007 CONFERENCE CALL
10:00 AM TO 3:00 PM CENTRAL
DRAFT MINUTES

1. Welcome

Mr. Wood opened the meeting and welcomed the meeting participants. Ms. Kennedy read the antitrust guidelines. Mr. Busbin moved, seconded by Ms. York, to adopt the agenda with the addition of Item 5 – Review Final MOD001 for Informal Comments. The motion passed without objection.

2. Request No. R05004 Item 1A (*where the allocation of flowgate capability based on historical Network Native Load impacts the evaluation of transmission service requests, requiring the posting of those allocation values in conjunction with queries of service offerings on OASIS*)

Mr. Middleton submitted draft language for Item 1A posted as a work paper for this meeting: http://www.naesb.org/pdf2/weq_atc_afc020907w10.doc. Mr. Middleton also provided several additional work papers as background that were posted as work papers for this meeting.

The subcommittee reviewed the language drafted by Mr. Middleton. Mr. Pritchard asked the meaning of the term "seasonal values" in R11. Mr. Middleton stated that seasonal is used by the OATI Software and calculates the values every six months. FERC requires MISO to post ASTFC for eighteen months at a time.

Mr. Wood asked if the AFC is positive and the ASTFC is negative whether that will give a customer the wrong idea of how much capacity is available on that particular flowgate. Mr. Middleton stated that the second introductory paragraph of the work paper states that a mechanism is in place to "either 'share' or "transfer" a portion of their allocation". If another reciprocal entity has a positive ASTFC, MISO takes it and does not have to provide notification. If a Transmission Customer is refused due to ASTFC, that means that none of the reciprocal parties have any ASTFC. The problem Mr. Kimm has cited in the past was prior to MAAP having a Seams Operating Agreement and the issues with the flowgate right on the seam should not happen in the future.

Mr. Middleton reviewed the work paper posted: Copy of MISO NNLASTFC Report. He stated that MISO posts this spreadsheet updated every day. Mr. Pritchard asked if Mr. Middleton was proposing that all RTOs post each ASTFC. Mr. Middleton stated that all RTOS do post this information now. He added that OATI, as the contractor, puts the file so everyone accesses the same file so all RTOs show the same ASTFC for a flowgate.

Mr. Middleton stated it was his intent to submit the draft standards language for the participants to review and add additional substance for more robust requirements. Mr. Wood stated that the group would review this language and discuss at the next meeting.

3. R05004A Item 3E (business practices for calculation and frequency of posting ATC calculation)

Ms. Rehman submitted a work paper to address Item 3E: ATC Information recommendation - B. Rehman, BPA. The subcommittee reviewed the work paper submitted by Ms. Rehman.

Ms. York suggested adding language similar to the Standards of Conduct link on OASIS standards: to establish a link and then prescribe the information that should be found behind the link for ATC posting requirements. Ms. Otonco stated that the language for this item cannot be completed until the OATT Order is issued.

The subcommittee agreed to add more specificity to this language once MOD01 is posted for formal comment and/or the OATT Order is issued.

4. Review Request No. R05004A "CBM Items"

Mr. Wood stated that these portions of the Request will be on the agenda for the March 1-2 meeting. NAESB needs to determine how it plans to draft standards regarding the posting of these items and how to maintain the calculations and whether the calculation methods also need to be posted. CBM and TRM will be on the agenda for the joint meeting with the NERC ATC Drafting Team on March 1-2, 2007.

5. Review Final MOD001 for Informal Comments

Next, the subcommittee reviewed the draft of MOD001 that NERC plans to post for comments on February 15, 2007: MOD-001 2/8/07.

Mr. Saini, as a member of the NERC ATC Drafting Team, stated that on the last review, the NERC Team did not change definitions, but removed definitions of time horizons; addressed formatting and consistency issues pointed out by Ms. Long. The NERC Team did respond to comments made on an earlier draft by the NAESB ESS/ITS and BPS. Mr. Saini urged individuals to submit comments on behalf of their companies if there are comments on the substance of the document.

The only comment the subcommittee decided to forward to the NERC ATC Drafting Team via Mr. Lohrman was on the box in the margin associated with R4: For the yellow box that corresponds with R4, the participants thought the text should state "The requirements for calculating TFC, TRM, CBM and ETC will be developed in separate sets of standards" instead of "…TTC, TRM, CBM, and ETC". Ms. Kennedy stated she would forward this note to Mr. Lohrman so that it can be modified before MOD001 is posted for comment on February 15th.

The subcommittee also reviewed the comment form that will be distributed with MOD001: http://www.naesb.org/pdf2/weq_atc_afc020907w6.doc.

6. Other Business/Next Steps/Future Meetings

Mr. Pritchard stated that during the March 1-2 meeting, the NERC and NAESB groups working on ATC should conduct a review of the joint development procedure and provide feedback on how the process is working for the members of NERC and NAESB. Mr. Pritchard stated that is may not be necessary to review comments jointly with NERC on MOD001. He stated that joint review of comments may slow the process down. Ms. York stated that while the joint development procedure provides for joint review of comments, she would speak with Ms. McQuade about Mr. Pritchard's comments.

The subcommittee has the following meetings/conference calls scheduled:

- **March 1-2, 2007:** The NAESB ESS/ITS and BPS agreed to schedule this meeting as a joint meeting with the NERC ATC Drafting Team. Mr. Lohrman stated that the meeting will be in either Memphis, TN or Nashville, TN. The meeting will be from 12:00 AM to 5:00 PM on March 1 and from 8:00 AM to 12:00 PM on March 2. NERC is the host of this meeting and will provide the agenda, work papers, and meeting administration for this meeting. The agenda for this meeting will include:
  - NAESB Comments on MOD003
  - CBM, TRM
  - FAC12 and FAC 13
  - FERC Order on OATT Reform Docket
  - Discussion of joint development procedure
- **March 7, 2007:** Conference call of the NAESB ESS/ITS and BPS from 10:00 AM to 3:00 PM Central
- **April 17, 2007:** Meeting of the NAESB ESS/ITS and BPS in Houston, Texas hosted by NAESB. Meeting times are 10:00 AM to 4:00 PM Central.
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7. Adjourn

The meeting adjourned by consensus at 2:36 PM Central.

8. Attendance

Name	Organization
Mark Anderson	Seminole Electric
Rebecca Birdall	BPA
Jim Busbin	Southern Company
Blaine Earhart	Basin Electric
Laura Kennedy	NAESB
Larry Middleton	MISO
Marcy Otonco	Arizona Public Service
Bob Pierce	Duke Energy
Alan Pritchard	Duke Energy
Barbara Rehman	BPA
Narinder Saini	Entergy
Martin Summe	ElectriCities
JT Wood	Southern Company
Kathy York	Tennessee Valley Authority

Attachment 2b

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REGULATORY ALERT BULLETIN

February 18, 2007

FERC'S OPEN ACCESS FINAL RULE[1]

For additional information, please contact:

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INTRODUCTION

On February 15, 2007, the Federal Energy Regulatory Commission ("FERC") issued, in Docket Nos. RM05-17-000 and RM05-25-000, its Final Rule on open access regulations and amendments to Order Nos. 888[2] and 889.[3] This Regulatory Alert Bulletin identifies major aspects of the Final Rule and highlights areas where FERC has modified its approach from the proposal contained in the Notice of Proposed Rulemaking ("NOPR"), issued on May 19, 2006. The Final Rule requires public utilities to file amendments to their *pro forma* open access tariffs and significantly modify current Open Access Same-Time Information System ("OASIS") practices.

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[1] DISCLAIMER – The information provided in this Regulatory Alert Bulletin does not constitute, nor should it be construed as, legal advice. Receipt of this Regulatory Alert Bulletin and/or its contents does not establish an attorney-client or other relationship between Troutman Sanders LLP (including its attorneys) and the recipient.

[2] *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 61 Fed. Reg. 21,540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh'g*, Order No. 888-A, 62 Fed. Reg. 12,274 (Mar. 14, 1997), FERC Stats. & Regs. ¶ 31,048 (1997), *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000) (*TAPS v. FERC*), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002).

[3] *Open Access Same-Time Information System (Formerly Real-Time Information Networks) and Standards of Conduct*, Order No. 889, 61 Fed. Reg. 21737 (May 10, 1996), FERC Stats. & Regs. ¶ 31,035 (1996), *order on reh'g*, Order No. 889-A, FERC Stats. & Regs. ¶ 31,049 (1997), *order on reh'g*, Order No. 889-B, 81 FERC ¶ 61,253 (1997).

The Final Rule will become effective 60 days after publication in the Federal Register.

I. SUMMARY, SCOPE, AND APPLICABILITY OF THE FINAL RULE

FERC reformed the *pro forma* Open Access Transmission Tariff ("OATT") in order to address deficiencies that have become clear since the OATT was developed in 1996. Final Rule at P 1. Significant aspects of the Final Rule include the following:[4]

- **ATC Calculation**: FERC reforms the Available Transfer Capability ("ATC") calculation requirements in the OATT. Public utilities are to work with the North American Electric Reliability Council ("NERC") and the North American Energy Standards Board ("NAESB") to develop greater consistency in inputs, calculations, and data exchange, in order to increase transparency. More detail is required to be included in the OATT and additional information must be posted on the OASIS.

- **Transmission Planning**: FERC requires a more inclusive transmission planning process incorporating nine principles: (1) coordination, (2) openness, (3) transparency, (4) information exchange, (5) comparability, (6) dispute resolution, (7) regional participation, (8) economic planning studies, and (9) cost allocation for new projects.

- **Transmission Pricing**: FERC modifies certain pricing rules including: (1) revising energy and generator imbalance charges; (2) eliminating the requirement that new facilities may receive credits only if they are "jointly planned;" and (3) lifting the cap on capacity reassignment pricing. FERC also clarifies its policies on operational penalties, including unreserved use penalties and the distribution of penalty proceeds.

- **Ancillary Services:** FERC amends Schedules 2 – 6 and Schedule 9 of the *pro forma* OATT to state that the ancillary services of Reactive Supply and Voltage Control, Regulation and Frequency Response, Energy Imbalance, Spinning Reserves, Supplemental Reserves, and Generator Imbalance, may be provided by generating units or non-generating resources, where appropriate.

- **Point-to-Point Service**: FERC modifies point-to-point service by clarifying that a transmission provider must use all of its available redispatch options to satisfy a request for firm point-to-point service, and, if the customer chooses, these redispatch options must be studied before the transmission provider commences a facilities study. In addition, transmission providers must offer conditional firm transmission service. The Final Rule rejects the proposal in the NOPR to require hourly Firm Point-to-Point Service.

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[4] For a summary of significant differences between the language of the currently-effective *pro forma* OATT and the *pro forma* OATT language in the Final Rule, please see the chart in Appendix A that identifies tariff language modifications by tariff sheet number. Additionally, Appendix B is a summary chart of changes between the *pro forma* OATT language from the NOPR and the *pro forma* OATT language contained in the Final Rule. The charts do not include non-significant changes (corrected typos, section numbering changes, conforming changes, and very minor wording changes).

FERC also clarifies that pre-confirmed short-term point-to-point requests will have priority over requests that are not pre-confirmed and that have equal or shorter duration.

- **Rollover Rights**: FERC requires that contracts with rollover rights must have a minimum term of five years and that customers notify transmission providers one year in advance that they will be renewing their rights.

- **Acquisition of Transmission Service**: FERC requires that transmission providers post specific performance metrics regarding the timely completion of required studies. FERC also clarifies the priority for pre-confirmed requests for service.

- **Penalties:** FERC will subject transmission providers to penalties if they persistently fail to meet deadlines for completing required studies.

- **Network Resources**: FERC requires transmission providers and network customers to use the transmission provider's OASIS to request designation of, or termination of, network resources and clarifies the types of resources that can be designated.

- **Transparency / OASIS**: FERC requires that transmission providers post: (1) specific performance metrics related to completion of studies under the OATT; and (2) all rules, standards and practices that relate to terms and conditions of transmission service.

- **Credit Standards**: The Final Rule amends the *pro forma* OATT to include an attachment that describes the transmission provider's basic credit standards.

- **Reciprocity:** The Final Rule modifies the reciprocity provision to specify that, if an Independent Transmission System Operator ("ISO") or Regional Transmission System Operator ("RTO") is the transmission provider, the reciprocity obligation is owed to all members of that ISO or RTO.

- **Compliance**[5]

    - Transmission providers that have not been approved as ISOs or RTOs, and whose transmission facilities are not under the control of an ISO or RTO, must submit FPA section 206 compliance filings that contain the revised non-rate terms and conditions set forth in the Final Rule within 60 days following its publication in the Federal Register. The filing need only contain the revised provisions of the Final Rule and not the transmission provider's entire *pro forma* OATT. Additional compliance filings are required in 120 days (capacity benefit margin charges), 180 days (ATC), and 210 days (transmission planning).

[5] See Part V. of this summary for the Final Rule's chart of major compliance filing deadlines (pages 1061-61), with a few additions.

- For those non-ISO/RTO transmission providers that have received approval from FERC to adopt variations from the non-rate terms and conditions of the *pro forma* OATT, the Final Rule provides a two-tiered compliance process. First, if the variations previously adopted will not be affected in a substantive manner by the reforms of *pro forma* OATT by the Final Rule, the variations may remain in place. Second, if the Final Rule modifies the previously-approved *pro forma* variations, the non-ISO/RTO transmission provider must demonstrate that the previously adopted variations continue to be consistent with or superior to the new *pro forma* OATT. The non-ISO/RTO transmission providers may submit a FPA section 205 filing within 30 days after the publication of the Final Rule to seek a determination that the variation continues to be acceptable.

- ISO and RTO transmission providers must file 210 days after publication, an FPA section 206 compliance filing that contain non-rate terms and conditions set forth in the Final Rule or demonstrate that their existing tariff provisions are consistent with or superior to the revised provisions.

II. BACKGROUND

A. Procedural History

- FERC issued a Notice of Inquiry ("NOI") on September 16, 2005. In response, parties filed over 4,000 pages of initial and reply comments.

- FERC issued the NOPR on May 19, 2006.[6] Another 5,700 pages of initial and reply comments were submitted.

- On October 12, 2006, FERC held a technical conference that focused on three main areas: transmission planning, ATC calculation, and redispatch and conditional firm service.

- FERC issued a Notice of Request for Supplemental Comments on November 15, 2006,[7] and received an additional 750 pages of comments.

B. Legal Justifications for Changes

- FERC concludes that reforms to the *pro forma* OATT are necessary to limit remaining opportunities for undue discrimination, particularly in areas where the *pro forma* OATT leaves the transmission provider with substantial discretion.[8] Final Rule at PP 39-40.

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[6] *Preventing Undue Discrimination and Preference in Transmission Service*, Notice of Proposed Rulemaking, 71 Fed. Reg. 32,636 (Jun. 6, 2006), FERC Stats. & Regs. ¶ 32,603 (2006).

[7] *Preventing Undue Discrimination and Preference in Transmission Service*, 117 FERC ¶ 61,185 (2006).

[8] FERC notes that it does not have to make specific findings of discrimination in order to promulgate a generic rule to eliminate undue discrimination. Final Rule at P 41.

- FERC states that inadequate transparency requirements, combined with inadequate compliance with existing OASIS regulations, increases opportunities for undue discrimination and makes instances of undue discrimination harder to detect. Final Rule at P 51.

- FERC states the *pro forma* OATT has very few requirements regarding how transmission planning should be conducted to ensure that undue discrimination does not occur. Final Rule at P 57. This flaw is notable because of the critical need for new transmission infrastructure to alleviate congestion on the grid. Final Rule at P 58.

- FERC finds that transmission providers have too much discretion under the *pro forma* OATT in the calculation of ATC, which has resulted in a variety of ATC calculation methodologies in use today, very little transparency regarding the nature of the calculations, and very few clear rules governing their use. Final Rule at PP 62, 69.

- FERC notes that existing policies provide wide discretion in the development of imbalance energy charges. Final Rule at P 70.

- Under the Final Rule, the two techniques (planning redispatch and conditional firm services) that are used by transmission providers to serve native load will also be available to transmission customers in order to avoid undue discrimination, facilitate the provision of long-term transmission service and provide customers with greater flexibility in choosing resources to meet their needs. Final Rule at P 78.

- FERC states that its Final Rule is consistent with policies and provisions of the Energy Policy Act of 2005 ("EPAct 2005"), including: (1) facilitating the development of transmission infrastructure; (2) improving transparency in the electricity markets; and (3) increasing compliance with applying civil and criminal penalties for violation of those regulations. Final Rule at PP 79-81.

III. MAJOR MODIFICATIONS OF THE OATT

A. ATC Calculations: Consistency and Transparency

- "ATC" means available transfer capability. Although FERC used the term "Available Transmission Capability" in Order No. 888, the *pro forma* OATT will be revised to be consistent with the NERC definition of ATC, which is the transfer capability remaining on the system for further commercial activity over and above already committed uses.

- Under Order Nos. 888 and 889, each public utility calculates ATC. Instead of prescribing a specific methodology for calculating ATC, FERC encouraged the industry to develop a consistent, industry-wide approach. Order No. 890 finds that this process has been unsuccessful. Final Rule at P 68.

- FERC directs public utilities, working through NERC reliability standards and NAESB business practices development processes, to improve the consistency and transparency of ATC calculations. Final Rule at P 196. Public utilities must develop standards that ensure consistency in ATC calculation components, data inputs, modeling assumptions, and data exchange among transmission providers.

- FERC also increases transparency of ATC calculations by requiring each transmission provider's OATT to include its specific ATC calculation methodology, and to post relevant data and models on each transmission provider's OASIS. FERC does not establish a single methodology for calculating ATC, due to the burden of developing and adopting a uniform software package to calculate ATC. Final Rule at P 208.

1. Consistency

(a) Necessary Degree of Consistency

- The transmission provider must provide, in Attachment C, detailed descriptions for calculating both firm and non-firm ATC. FERC expects that there will only be a few industry-wide ATC calculation formulas. Final Rule at P 207.
- FERC believes that the three ATC calculation methodologies being finalized by NERC (contract path, network ATC, and network AFC) will produce predictable and sufficiently accurate, consistent, equivalent, and replicable results if there is industry-wide consistency of all: (1) ATC components (Total Transfer Capacity ("TTC"), Existing Transmission Commitments ("ETC"), Capacity Benefit Margin ("CBM"), and Transmission Reliability Margin ("TRM")) and certain data inputs and exchange; (2) modeling assumptions; (3) ATC calculation frequency; and (4) coordination of data relevant for the calculation of ATC. Final Rule at P 210.
- Because posted Available Flowgate Capacity ("ATC") values must be associated with a particular path (not AFC values associated with a flowgate), transmission providers using an AFC methodology must convert flowgate values into ATC path values for OASIS posting. Public utilities, working through NERC are to develop in the MOD-001 standard a rule to convert AFC into ATC values. Final Rule at P 211.
- Public utilities working with NERC are to modify related ATC standards by implementing the following principles for firm and non-firm ATC calculations: (1) for ATC calculations, the transmission provider shall account only for firm commitments; and (2) for non-firm ATC calculations, the transmission provider shall account for both firm and non-firm commitments, postbacks of redirected services, unscheduled service, and counterflows. Each transmission provider's Attachment C must include a detailed formula for both firm and non-firm ATC, consistent with the modified ATC-related reliability standards. Final Rule at P 212.

(b) Process to Achieve Consistency

- FERC directs public utilities, working through NERC, to modify the ATC-related reliability standards within 270 days of publication in the Federal Register. Final Rule at

PP 221, 223. Public utilities must work through NAESB to develop business practices that complement NERC's new reliability standards within 360 days of publication in the Federal Register. Also, within 90 days of publication in the Federal Register, NERC and NAESB must file a joint status report on standards and business practices development and a work plan for completion of this task. Final Rule at P 223.

(c) ATC Components

- TTC/TFC: public utilities, working through NERC, are to develop consistent TTC or total flowgate capacity ("TFC") calculation methodologies. Final Rule at P 237. FERC states that the TTC requirements will be determined by the NERC reliability standards and any request for a regional difference from the reliability standards must take place through the NERC process. Final Rule at P 238.
- ETC: Public utilities, working through NERC and NAESB, are to develop a consistent approach for determining the amount of transfer capability a transmission provider may set aside for its native load and other committed uses. Final Rule at P 243. ETC must include committed uses of the transmission system, including: (1) native load commitments (including network service), (2) grandfathered transmission rights, (3) appropriate point-to-point reservations, (4) rollover rights associated with long-term firm service, and (5) other uses identified through the NERC process. ETC should not be used to set aside transfer capability for any type of planning or contingency reserve, which are to be addressed by CBMs and TRMs. All reserved, but unused, transfer capability (non-scheduled) shall be released as non-firm ATC. Final Rule at P 244.
- Public utilities, working through NERC, are to develop requirements in MOD-001 laying out clear instructions on how reservations that have the same Point of Receipt ("POR") (generator) but different Point of Delivery ("POD") (load) should be accounted for. *These reservations should not be modeled in the ETC calculation simultaneously if their combined reserved transmission capacity exceeds the generator's nameplate capacity at POR*. Final Rule at P 245. Because some elements of ETC can be managed via business practices rather than reliability standards, FERC directs public utilities, working through NAESB, to develop business practices necessary for full implementation of the developed MOD-001 reliability standard. Final Rule at P 246.
- CBM: Despite concerns that transmission providers have preferential access to the interface capacity that is set aside for CBM, FERC concludes that Load Serving Entities ("LSEs") should be able to retain the option of setting aside transfer capability in the form of CBM to maintain their generation reliability requirement. Final Rule at PP 256, 259. FERC requires public utilities, working though NERC and NAESB, to develop clear standards for how the CBM value shall be determined, how CBM is allocated across transmission paths, and how CBM is used. Final Rule at PP 257, 260. Transmission providers must reflect the set-aside of transfer capability as CBM in the development of the rate for Point-to-Point transmission service. Final Rule at P 257. Public utilities are required to work through NERC to modify the CBM-related standards to specify the generation deficiency conditions during which an LSE will be allowed to use the transfer capability reserved as CBM. Additionally, transmission set aside as CBM shall be zero in non-firm ATC calculations. FERC orders public utilities to work

with NAESB to develop an OASIS mechanism that will allow for auditing of CBM usage. Final Rule at P 262.

- Transmission providers are to design their transmission charges to ensure that the class of customers not benefiting from the CBM set-aside, *i.e.*, Point-to-Point customers, do not pay a transmission charge that includes the cost of the CBM set-aside. Transmission providers must submit redesigned transmission charges that reflect the CBM set-aside through a limited issue FPA section 205 rate filing as part of their initial ATC-related compliance filing. These filings, to be submitted within 120 days after the publication of the Final Rule in the *Federal Register*, may be limited to the rate design change only, *i.e.*, they will not require the submission of cost of service data or a revision to the transmission provider's revenue requirement. Final Rule at P 263.
- TRM: Public utilities, working through NERC, are to complete the ongoing process of modifying TRM standards MOD-008 and MOD-009. Final Rule at P 272. FERC adopts the NOPR proposal to establish standards specifying the appropriate uses of TRM to guide NERC and NAESB in the drafting process. Transmission providers may set aside TRM for: (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, (6) automatic sharing of reserves, and (7) other uncertainties as identified through the NERC process. FERC does not require transfer capability that is set aside as TRM to be sold on a non-firm basis. Final Rule at P 273. FERC directs public utilities, working through NERC, to establish an appropriate maximum TRM. Final Rule at P 275. Each Transmission Provider must calculate, and allocate on the paths and flowgates, the aggregate TRM value for all LSEs within its area and make available all underlying documentation, including work papers and load flow base cases, used to determine TRM, to any transmission customer and LSE within its control area, subject to a confidentiality agreement, if necessary. Final Rule at P 276.

(d) Modeling, Assumptions, and Input Data

- FERC directs public utilities, working through NERC, to modify the reliability standards MOD-010 through MOD-025 to incorporate a requirement for the periodic review and modification of models for: (1) load flow base cases with contingency, subsystem, and monitoring files, (2) short circuit data, and (3) transient and dynamic stability simulation data, in order to ensure that they are up to date. Models should be updated and benchmarked to actual events. Final Rule at P 290.
- FERC adopts the NOPR proposal to require transmission providers to use data and modeling assumptions for the short- and long-term ATC calculations that are consistent with that used for the planning of operations and system expansion, respectively, to the maximum extent practicable. This includes: (1) load levels, (2) generation dispatch, (3) transmission and generation facilities maintenance schedules, (4) contingency outages, (5) topology, (6) transmission reservations, (7) assumptions regarding transmission and generation facilities additions and retirements, and (8) counterflows. FERC directs public utilities, working through NERC in MOD-001, to modify ATC standards to achieve this consistency. Final Rule at PP 292, 295.

- With respect to modeling of generation dispatch, public utilities, working through NERC, are to develop requirements in NERC's MOD-001 specifying how transmission providers shall determine which generators should be modeled in service, including guidance on how independent generation should be considered. FERC also specifies that base generation dispatch will model: (1) all designated network resources and other resources that are committed or have the legal obligation to run, as they are expected to run, and (2) uncommitted resources that are deliverable within the control area, economically dispatched as necessary to meet balancing requirements. Final Rule at P 296.
- Regarding transmission reservations modeling, FERC directs public utilities, working through NERC, to develop requirements in reliability standard MOD-001 that specify: (1) a consistent approach on how to simulate reservations from points of receipt to points of delivery when sources and sinks are unknown and (2) how to model existing reservations. Final Rule at P 297.

(e) ATC Calculation Frequency

- Public utilities, working through NERC and NAESB, must revise reliability standard MOD-001 to require ATC to be recalculated by all transmission providers on a consistent time interval and in a manner that closely reflects the actual topology of the system, *e.g.*, generation and transmission outages, load forecast, interchange schedules, transmission reservations, facility ratings, and other necessary data. Final Rule at P 301.

(f) Data Exchange

- FERC will require public utilities, working through NERC, to revise the related MOD reliability standards to require the exchange of data and coordination among transmission providers and, working through NAESB, to develop complementary business practices. The following data shall, at a minimum, 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 recalculation frequency and times; and (7) source/sink modeling identification. Because transmission providers are required to coordinate the calculation of TTC/TFC and ATC/AFC with others, this requires a standard means of exchanging data. Final Rule at P 310.

- FERC acknowledges the concerns of ISO/RTOs that new data exchange protocols may interfere with the existing protocols and seams coordination agreements and, therefore, ISO/RTOs may demonstrate in relevant filings that their existing data exchange protocols are consistent with or superior to those that are developed in the NERC and NAESB processes. Final Rule at P 311.

2. Transparency

- FERC requires transmission providers to take certain measures to make their ATC calculation process more transparent.

(a) OATT Transparency

- Each Transmission Provider must, at a minimum, include the following information in Attachment C to its OATT: (1) clear identification of the NERC-approved methodologies it employs (contract path, network ATC, or network AFC); (2) a detailed description of the specific mathematical algorithm the transmission provider uses to calculate firm and non-firm ATC for the scheduling horizon (same day and real-time), operating horizon (day ahead and pre-schedule), and planning horizon (beyond the operating horizon); (3) inclusion of a process flow diagram that describes the various steps that it takes in performing the ATC calculation; and (4) a definition of each ATC component (i.e., TTC, ETC, TRM, and CBM) and a detailed explanation of how each one is derived in both the operating and planning horizons. Final Rule at P 323. Transmission providers are also required to document their processes for coordinating ATC calculation with their neighboring systems. Final Rule at P 326.

- Attachment C must also contain a description detailing the CBM practices, explain the definition of CBM, and list the databases used to derive its value. Final Rule at P 337.

(b) OASIS

- FERC adopts the proposal in the NOPR to continue to require transmission providers to comply with existing ATC-related posting obligations, and requires Transmission providers, on request, to make available all data used to calculate ATC and TTC for any constrained paths and any system planning studies or specific network impact studies performed for customers. Transmission providers must also continue to post a list of such studies on OASIS. Final Rule at P 348. FERC also requires the additional posting of, at a minimum, a listing of all system impact studies, facilities studies, and studies performed for the transmission provider's own network resources and affiliated transmission customers, to be made available upon request. Appropriate procedures to accommodate CEII concerns should be developed to ensure eligible entities with a legitimate interest in transmission study data can receive access to it. Studies should be made available for five years, consistent with data retention requirements pertaining to denial of service requests. Final Rule at P 349.

- FERC amends the OASIS regulations to incorporate the directives established in the CBM Order[9] and requires transmission providers to post (and update) the CBM amount for each path. In addition, transmission providers are to make any transfer capability set aside for CBM but unused for such purpose (1) available on a non-firm basis and

[9] *Capacity Benefit Margin in Computing Available Transmission Capacity*, 88 FERC ¶61,099 (1999).

(2) posted as available on OASIS. Furthermore, transmission providers are to post (and update) the TRM values for the paths on which the transmission provider already posts ATC, TTC, and CBM. Final Rule at P 354.

- FERC requires CBM studies to be performed at least every year. Final Rule at P 358.

- FERC requires transmission providers to post a brief, but specific, narrative explanations for changes in monthly and yearly ATC values on a constrained path. FERC will require a narrative when a monthly or yearly ATC value changes only as a result of a 10 percent change in TTC. Posted information include: (1) the specific events which gave rise to the change; and (2) new values for ATC on that path (as opposed to all points on the network). Final Rule at P 369. FERC will also require a narrative with regard to monthly or yearly ATC values when ATC remains unchanged at a value of zero for a significant period, and sets that period at six months or longer. Final Rule at P 371.

- FERC maintains the requirement that a transmission provider post the reason for a denial of service and extends from three years to five years the period for which transmission providers must maintain data providing reasons for denial of service. Final Rule at P 376. FERC also expands the regulations to include availability of information supporting the disposition of a transmission provider's own network resource designations and to make such information available to any eligible customer rather than just to the customer denied service. FERC also clarifies that a partial denial of service triggers the requirements as well. The development of a log of service denials, full or partial, will establish an ongoing record of service requests and transmission provider responses demonstrating the transmission provider's provision of nondiscriminatory open access service. Final Rule at P 377.

- FERC requires transmission providers and network customers to use OASIS to request designation of new network resources and to terminate designation of network resources. This information shall be posted on OASIS for 90 days and available for audit for a five-year period. Transmission customers thus shall be able to query requests to designate and terminate a network resource. FERC orders public utilities, working through NAESB, to develop appropriate templates for OASIS. Final Rule at P 385.

- FERC affirms that transfer capability associated with transmission reservations that are not scheduled in real time are required to be made available as non-firm, and posted on OASIS. Final Rule at P 389.

- Although acknowledging the security and confidentiality concerns raised by commenters, FERC asserts that those with a need to obtain CEII information must be able to obtain it on a timely basis. Final Rule at P 403. Therefore, FERC requires transmission providers to establish a standard disclosure procedure for CEII. Transmission providers may: (1) set up additional login requirements and (2) require customers to sign a nondisclosure agreement at the time that the customer obtains access to this portion of the OASIS. Final Rule at P 404.

- FERC requires that the metrics related to the provision of transmission service under the OATT be posted on OASIS.

- Transmission providers must post: (1) the number of affiliate versus non-affiliate requests for service that have been rejected, and (2) the number of affiliate versus non-affiliate requests for service that have been made. This posting must detail the length of service request (*e.g.*, short-term or long-term) and the type of service requested (*e.g.*, firm point-to-point, non-firm point-to-point or network service). FERC also requires transmission providers to post their underlying load forecast assumptions for all ATC calculations and to post, on a daily basis, their actual daily peak load for the prior day. FERC directs transmission providers to work through NAESB to develop standards for consistent methods of posting the new requirements on OASIS. Final Rule at P 413.

- FERC notes that affiliate posting requirements do not apply to RTOs and ISOs because they do not have affiliates to transact with. Final Rule at P 414. RTO and ISO load data needs to be posted at a sufficient granularity to allow for meaningful comparison of control area and LSE load levels, and FERC directs ISOs and RTOs to post load data for the entire ISO/RTO footprint and for each LSE or control area footprint within the ISO/RTO.

- FERC also finds that the peak load applies to system-wide load, including native load and, therefore, transmission providers are directed to post load forecasts and actual daily peak load for both system-wide load (including native load) and native load, as this data will be useful to customers and regulators. Final Rule at P 416.

B. Transmission Planning

1. Need for Reform

- The OATT is not sufficient to encourage non-discriminatory transmission expansion in an era of congestion and under-investment in the transmission grid and does not sufficiently counter the incentives for transmission owners to expand the system in a manner that favors their generation and their native load. Final Rule at PP 422-423.

- FERC concludes that it is necessary to require coordinated, open, and transparent transmission planning on both a local and regional level. Final Rule at P 435.

2. New Planning Requirements

- Each public utility transmission provider is required to submit, as part of a compliance filing, a proposal for a coordinated and regional planning process that complies with the planning principles and other requirements in the Final Rule. Final Rule at P 437. Alternatively, transmission providers may make a compliance filing describing their existing coordinated and regional planning process, including the appropriate language in their tariff, and show that their existing process is consistent with or superior to the requirements in the Final Rule. Final Rule at P 437.

- FERC does not intend to reopen prior approvals of ISOs and RTOs that already have established regional transmission planning processes, but will require them to make a showing that their processes comply with the Final Rule. FERC notes that transmission owning members of RTOs must also comply with the Final Rule and participate in the planning process. Final Rule at P 439-440.

3. Compliance Deadline

- Transmission planning processes must be contained in an attachment to the OATT to be filed within 210 days after the publication of the Final Rule. Final Rule at P 442.

4. Technical Conferences

- FERC will convene staff technical conferences in several regions to discuss regional implementation 3-4 months after publication of the Final Rule. Final Rule at P 443.

- To facilitate these conferences, each transmission provider should, within 75 days after the publication of the Final Rule, post a "strawman" proposal for compliance with each of the planning principles, including a specification of the broader region in which it will conduct coordinated regional planning. Final Rule at P 443.

5. Planning Principles

- The Final Rule contains 9 Transmission Planning Principles that FERC would like to guide the transmission planning process. This adds one guideline to those in the NOPR.

  - Coordination – The transmission provider must meet with all of its transmission customers and interconnected neighbors to develop a transmission plan. FERC notes that meetings might be complemented by a standing planning committee. Final Rule at P 452. Customers must be included at the early stages of the development of the transmission plan and not merely given an opportunity to comment on transmission plans that were developed in the first instance without their input. Final Rule at P 454.

  - Openness – Transmission planning meetings must be open to all affected parties. While some circumstances require planning efforts of smaller groups, the process must remain open. Final Rule at P 460.

  - Transparency – The transmission provider is required to disclose to all customers and other stakeholders the basic criteria, assumptions, and data that underlie its planning, including how it treats retail native loads, in order to ensure that standards are consistently applied. Final Rule at P 471. FERC also requires that transmission providers make available information regarding the status of upgrades identified in their transmission plans and reiterates that non-public utility transmission providers should abide by the Standards of Conduct with regard to managing non-public transmission planning information obtained through the planning process, consistent

with their reciprocity obligations. Final Rule at PP 472-474. FERC finds Form 715 is an insufficient basis for broad transmission planning purposes and must be supplemented by additional assumptions and data. Final Rule at P 477. Where demand resources are capable of providing the functions assessed in a transmission planning process, and can be relied upon on a long-term basis, they should be included in the transmission planning process. Final Rule at P 479.

- Information Exchange – Transmission customers are required to submit information on their projected loads and resources on a comparable basis as used by transmission providers in planning for their native load at regular intervals, and the transmission provider must allow market participants the opportunity to review and comment on draft transmission plans. Final Rule at P 486.

- Comparability – The transmission system plan should meet the specific service requests of transmission customers and otherwise treat similarly situated customers comparably. Ultimate responsibility remains with transmission providers, and FERC rejects the arguments that comparability requires that customers have equal weight in decision-making. Final Rule at P 495.

- Dispute Resolution – FERC adopts the NOPR's proposal to require transmission providers to develop a dispute resolution process to manage disputes that arise from the Final Rule's planning process and that should address both procedural and substantive planning issues. Final Rule at PP 496, 501.

- Regional Participation – The transmission provider is required to coordinate with interconnected systems to share system plans and ensure that they are simultaneously feasible and identify system enhancements that could relieve significant and recurring transmission congestion. Final Rule at P 523. FERC urges participants in existing regional planning processes to closely examine whether improvements may be implemented to ensure that each regional planning process is fully consistent with the requirements of this Final Rule. Final Rule at P 526. FERC declines to mandate the geographic scope of particular planning regions at this time. Final Rule at P 527.

- Economic Planning Studies – The transmission provider is required to annually prepare studies identifying "significant and recurring" congestion and to post such studies on OASIS. FERC disagrees that economic upgrades should be considered only in the context of individual requests for service under the OATT. Final Rule at PP 542-543. FERC clarifies that it is not intending to establish a rule under which an obligation to study potential upgrades is equivalent to an obligation to fund or build such upgrades. Final Rule at P 544. This principle also applies to ISOs and RTOs. Final Rule at P 544. FERC modifies the NOPR principle to require that stakeholders be given the right to request a defined number of high priority studies annually (e.g., five to ten studies) to address congestion and/or the integration of new resources or loads. Final Rule at P 547. This principle covers the study of upgrades to integrate new generation resources or loads on an aggregated or regional basis. Final Rule at P 548.

- Cost Allocation for New Projects – This principle is not intended to replace current cost allocation rules but rather to apply to projects that do not fit under the existing structure. Final Rule at P 558. *Rather that imposing a particular allocation method, FERC permits transmission providers and stakeholders to determine their own criteria*. Final Rule at P 558. FERC recognizes that there is a free rider problem with cost allocation and encourages regional planning processes to come up with equitable rules. FERC provides several cost allocation principles: (1) whether a cost allocation proposal fairly assigns costs among participants, including those who cause them to be incurred and those who otherwise benefit from them; (2) whether a cost allocation proposal provides adequate incentives to construct new transmission; and (3) whether the proposal is generally supported by state authorities and participants across the region. Final Rule at P 561.

6. Independent Third Party Coordinator

- FERC adopts the NOPR proposal to not require the use of an independent third party coordinator at this time. Final Rule at PP 567-568.

7. State Commission Participation

- FERC encourages state commission participation and encourages states to coordinate with each other. FERC will defer to states where appropriate. Final Rule at P 575.

8. Flexibility in Implementation and Examples of Compliant Processes

- FERC makes clear that it does not endorse any specific existing process as a model for all transmission providers. Final Rule at P 582.

9. Recovery of Planning Costs

- FERC will not propose a specific method for recovery and allocation of planning costs. Final Rule at P 586.

10. Open Season for Joint Ownership

- FERC believes there are benefits to joint ownership of transmission facilities, but does not mandate open season procedures to allow market participants to participate in joint ownership. Final Rule at P 594.

11. Specific Study Processes Beyond Reliability and Congestion Reduction

- FERC believes that development of a study process for identifying opportunities for grid enhancement beyond reliability and congestion reduction (such as access to generation

resources) has the potential to provide useful information. FERC therefore will include such study processes within the scope of Principle No. 8. Final Rule at P 599.

12. Level of Planning Detail in the OATT

- FERC requires the transmission provider's OATT to include sufficient detail describing: (1) the process for consulting with customers and neighboring transmission providers; (2) the procedures and anticipated frequency of meetings or planning-related communications; (3) the methodology, criteria, and processes used to develop transmission plans; (4) the method of disclosure of transmission plans and related studies and the criteria, assumptions and data underlying those plans and studies; (5) the obligations of and methods for customers to submit data; (6) the dispute resolution process; (7) the transmission provider's study procedures for economic upgrades to address congestion or the integration of new resources; and (8) the relevant cost allocation procedures or principles. Final Rule at P 602.

C. Transmission Pricing

1. General

- FERC declines to address issues related to rate-pancaking, regional security constrained economic dispatch with LMP, or seams. Final Rule at PP 623-626.

2. Energy and Generator Imbalances

- FERC notes it has accepted a variety of different pricing methodologies and deviation bands for energy imbalance service. In the Final Rule, FERC adopts a standard methodology for imbalance service, in order to provide appropriate incentives for accurate scheduling, without being excessive. Final Rule at P 634.

(a) Three-Tiered Approach

- The imbalance provisions adopted in the new *pro forma* OATT are similar to those implemented by the Bonneville Power Administration. Tier 1 – Imbalances of less than or equal to 1.5% of the scheduled energy (or 2 MW, whichever is larger) are netted monthly and settled at 100% of the incremental or decremental cost. Tier 2 – Imbalances between 1.5% and 7.5% of the scheduled energy (or between 2 – 10MW, whichever is larger) are settled at 90% of the decremental cost for overscheduling or 110% of the incremental cost for underscheduling; and Tier 3 – Imbalances greater than 7.5% (or 10MW, whichever is larger) are settled at 75% of the decremental cost for overscheduling or 125% of the incremental cost for underscheduling. Final Rule at P 664.

- Intermittent resources are exempt from the third tier, and will pay second tier charges for all deviations of 1.5% or larger. An "Intermittent Resource" is "an electric generator that is not dispatchable and cannot store its fuel source and therefore cannot respond to

changes in system demand or respond to transmission security constraints." Final Rule at PP 665-666.

- This tiered approach applies to both energy (Schedule 4) and generation imbalances (a new Schedule 9). Final Rule at P 668.

- FERC will consider proposals for markets or pools to net or settle imbalances on a case-by-case basis. Final Rule at P 669.

- Transmission providers who have imbalance provisions that deviate from the OATT may re-file their proposals and seek renewed approval. The new imbalance provisions do not abrogate existing agreements. Final Rule at PP 670-671.

(b) Intentional Deviations

- FERC has not adopted penalties for intentional schedule deviations; rather, the imbalance penalties embodied in the three-tiered approach should be sufficient to discourage intentional power dumps or leans on other generation. Final Rule at P 676.

(c) Calculation of Incremental Cost

- For the purpose of imbalance charges, FERC has defined "incremental cost" as "the transmission provider's actual average hourly cost of the last 10MW dispatched to supply the transmission provider's native load, based on the replacement cost of fuel, unit heat rates, start-up costs, incremental operation and maintenance costs, and purchased and interchange power costs, as applicable." This definition will allow recovery of commitment and redispatch costs, but will exclude additional regulation reserve costs. Final Rule at PP 687, 689.

- The feasibility of using market prices will be assessed by FERC on a case-by-case basis. Final Rule at 692.

(d) Inadvertent Energy Treatment

- Inadvertent energy is the difference between a control area's net actual interchange and the net scheduled interchange. FERC will continue to allow inadvertent energy to be treated differently from imbalances. Under NAESB standards, inadvertent energy must be managed; the return-in-kind approach currently used is adequate, but if it is no longer sufficient for reliability, FERC may adopt a new standard. Final Rule at PP 702-703.

(e) Netting/Crediting of Energy and Generator Imbalances

- As a general rule, FERC is concerned that allowing netting and crediting of imbalances will undermine any incentive to adhere to scheduling. However, FERC will allow netting and crediting within the Tier 1 deviation band. Final Rule at PP 715-716.

(f) Intra-Hour Netting

- FERC will continue to allow net generation to be aggregated over the hour, but will consider proposals to adopt a shorter interval that is consistent with a transmission provider's relevant market structures. Final Rule at P 722.

(g) Distribution of Penalty Revenues above Incremental Cost

- Transmission providers are to develop and file mechanisms to credit penalty revenues above incremental costs to all non-offending transmission customers (including affiliated transmission customers). Final Rule at P 727.

3. Credits for Network Customers

- FERC severs the link between joint planning and credits for new facilities. A network customer will receive transmission credits if the facilities are integrated into the operations of the transmission provider's facilities and such facilities will be presumed integrated if they would be eligible for cost recovery under the transmission provider's annual revenue requirement. Final Rule at P 753.

- The new crediting provisions only apply to facilities added after the effective date of the Final Rule, not to pre-existing facilities. Final Rule at P 758.

- The costs associated with the transmission credits will not be automatically recovered in the transmission provider's cost of service. Transmission providers may propose an automatic adjustment clause under their rates to address the "lag time" between the costs incurred and the transmission provider's next rate case. Final Rule at P 766.

- Point-to-Point customers are not eligible for credits. Final Rule at P 770.

- RTOs and ISOs are not exempted; rather RTO and ISO issues relating to transmission credits will be considered in their compliance filings. Final Rule at P 773.

4. Capacity Reassignment

- FERC finds that the capacity reassignment market has failed to develop into a robust secondary market. As a stimulus, FERC removes the price cap for capacity reassignment (including capacity resold by the transmission provider's merchant function). Final Rule at PP 808-809.

- FERC will monitor the capacity reassignment market to ensure that it is developing properly. This includes the following reforms: (1) all sales or assignments of capacity are to be posted on the transmission provider's OASIS before the reassigned service commences (Final Rule at P 815); (2) assignees of transmission capacity must execute a service agreement before the reassigned service commences (Final Rule at P 816); (3) transmission providers are required to provide quarterly reports summarizing the

service agreements (Final Rule at P 817); and (4) FERC staff will closely monitor the reassignment data submitted by transmission providers in order to identify any problems, including the exercise of market power (Final Rule at P 820).

5. "Operational" Penalties

- If a transmission customer (or the transmission provider taking service under its own OATT) uses transmission service in excess of the capacity it has reserved, or uses unreserved transmission service, it will incur transmission use penalties. Final Rule at PP 834, 837, 840.

- Network customers are subject to penalties if they use network service to support off system sales. Final Rule at P 842.

- Transmission providers have discretion in setting their penalty rates, as long as penalty rates are based on the period of unreserved use. Final Rule at P 846. Also, transmission providers should respect the following criteria: (1) the unreserved use penalty for a single hour of unreserved use is based on the rate for daily firm point-to-point service (even if there is a rate for hourly firm service); (2) generally, more than one penalty assessment for a given duration will lead to an increase in the penalty assessment to the next given duration; thus, more than one daily penalty will lead to incurrence of a weekly penalty; and (3) the penalty rates must be stated explicitly. Final Rule at PP 846-848.

- Transmission providers must provide annual reports detailing the penalties received and distributed. Final Rule at P 861. All Point-to-Point and network customers, including native load customers, will be eligible to receive penalty distributions. Final Rule at P 862.

6. "Higher of" Pricing Policy

- In the NOPR, the Commission sought comment on whether, consistent with the "higher of" pricing policy, the incremental cost for a network upgrade should be presented as a monthly cost rather than a lump sum. Based on the comments received, FERC determined that it was not necessary to make changes to the OATT at this time to address this issue. Final Rule at P 883.

7. Other Ancillary Services

- FERC has amended Schedules 2 – 6 and Schedule 9 of the *pro forma* OATT to state that the ancillary services of Reactive Supply and Voltage Control, Regulation and Frequency Response, Energy Imbalance, Spinning Reserves, Supplemental Reserves, and Generator Imbalance, may be provided by generating units or non-generating resources, where appropriate. Final Rule at P 888.

D. Non-Rate Terms and Conditions

1. Modifications to Long-Term Firm Point-to-Point Service

- Planning redispatch involves an *ex ante* determination of whether out-of-merit order generation resources can be used to maintain firm service. Conditional firm service involves an *ex ante* determination of whether there are limited conditions or hours under which firm service can be curtailed to allow firm service to be provided in all other conditions or hours.

- FERC finds that both planning redispatch and conditional service are currently used under certain conditions by transmission providers to serve native load and determines that these services should be available to all customers in order to avoid undue discrimination. Final Rule at P 911.

- FERC states it will limit the availability of both service options so that the duration is for a time period over which service can be reasonably provided without impairing reliability. Final Rule at P 915. FERC finds that two years is the appropriate time period to allow the transmission provider to reassess the conditions under which redispatch or conditional firm service is provided. Final Rule at PP 959, 981.

(a) Implementation of Planning Redispatch and Conditional Firm

- Where a request for long-term point-to-point firm service is made and cannot be satisfied out of existing capacity, the transmission provider shall, at the request of the customer and in the system impact study, identify: (1) the transmission upgrades necessary to provide the service, and (2) the options for providing service during the period prior to completion of those transmission upgrades. If upgrades cannot be completed, the options subsequently studied must include planning redispatch and conditional firm options. Final Rule at P 957.

- FERC indicates that once the studies are completed, if planning redispatch is available, then the transmission provider shall provide the customer with non-binding estimates of the incremental costs of redispatch and identify the relevant constrained flowgates for which redispatch will be provided. Redispatch is available if it does not degrade or impair reliability of service or interfere with prior contractual commitments. Final Rule at P 946. If, alternatively, conditional firm is available, then the transmission provider shall identify the conditions and hours pursuant to which the service may be curtailed, using a secondary network curtailment priority to maintain reliability. Final Rule at P 958.

- The service agreement for the point-to-point service will specify whether the transmission provider will provide planning redispatch, a mix of planning redispatch and conditional firm, or conditional firm in order to provide the service. FERC states that any service agreement incorporating planning redispatch or conditional firm will be

considered a non-conforming agreement, and must be filed with FERC by the transmission provider. Final Rule at P 960.

(b) Eligibility and Timing for Planning Redispatch and Conditional Firm Options

- Both planning redispatch and conditional firm service need only be made available to customers who request firm point-to-point service of more than a year in duration. Final Rule at P 978.

- A system impact study that studies planning redispatch or conditional firm options must identify: (1) the system constraints; (2) additional direct assignment facilities or network upgrades required to provide the requested service; (3) redispatch options, including an estimate of the incremental costs of redispatch and the relevant congested transmission facilities for which redispatch will be provided; and (4) conditional firm options, including the number of conditional curtailment hours and the specific system conditions during which curtailment may occur. Final Rule at P 978.

- In the system impact study, the transmission provider must identify: (1) generation resources located within the transmission provider's control area, including its own resources, which can relieve the congested transmission facility at issue, and (2) the impact of each identified resource on the congested facilities. Final Rule at P 1003. The Final Rule also directs transmission providers to work with customers to facilitate the use of third party generation, where available, in provision of planning redispatch. Final Rule at P 1007. FERC specifically declined to adopt a commenter's proposal to expand transmission providers' real-time reliability redispatch obligations and incorporate third party bids into redispatch. Final Rule at P 1100.

- With regard to ISOs and RTOs, FERC states that it would be inappropriate to require such entities with real-time energy markets to adopt the provisions for conditional firm point-to-point service. Final Rule at P 992. However, FERC is requiring RTOs and ISOs to modify section 13.5 of the *pro forma* OATT to include monthly redispatch costs for each transmission facility over which planning and reliability redispatch are provided. Such revisions are not necessary if the RTO or ISO has previously been excused from including planning redispatch provisions in its OATT. Final Rule at P 993.

- FERC also places a limitation on the nature of the planning redispatch and conditional firm options based on whether the customer is supporting the construction of upgrades or not supporting such construction. For those supporting construction, the planning redispatch or conditional firm options will serve as a bridge until upgrades are constructed to remedy the congested transmission facilities. For customers not choosing to support the construction of new facilities, the planning redispatch or conditional firm options must be made available as a reassessment product and are subject to certain limitations. Final Rule at PP 979-981.

(c) Pricing of Planning Redispatch

- FERC adopts a new pricing method for planning redispatch service. FERC will no longer require the capping of redispatch costs over the term of the service at the costs of expansion. Final Rule at P 1023.

- Under the new pricing methodology, customers will have the options of paying: (1) the higher of (a) actual incremental costs of redispatch or (b) the applicable embedded cost transmission rate on file with the Commission; or (2) a fixed rate for redispatch to be negotiated by the transmission provider and customer and subject to a cap representing the total fixed and variable costs of the resources expected to provide the service. Final Rule at P 1024. If the customer selects the higher of incremental cost or the embedded cost-rate, the transmission provider shall calculate the costs of redispatch monthly and charge the higher of redispatch or the embedded cost rate each month. Final Rule at P 1024.

(d) Attributes of Conditional Firm

- Customers using the conditional firm service will pay the long-term firm point-to-point rate. Final Rule at P 1047. FERC also states there is no separate queue for the conditional firm option. Final Rule at P 1048.

- FERC indicates in the Final Rule that when conducting the system impact study for the conditional firm option, the transmission provider shall identify: (1) the specific system condition(s) when conditional curtailment may apply; and (2) the annual number of hours when conditional curtailment may apply. The customer is required to select either conditions or hours in its conditional firm service agreement. Final Rule at P 1064.

- FERC will allow for a sufficient time period for development of business practices and tracking mechanisms to implement the conditional firm service. Transmission providers located within the same region should coordinate such policies. Final Rule at P 1046.

- FERC will allow conditional firm point-to-point service to qualify as firm service that supports the designation of network resources imported from other control areas. FERC states this is appropriate because the conditional firm option only affects the transmission of the resource to the network, not the interruptibility of the generating resource itself. Final Rule at P 1091.

(e) Transparency for Redispatch Planning

- FERC adopts the following additional posting requirements for transmission providers. Transmission providers must post on OASIS: (1) their monthly average cost of redispatch for each internal congested transmission facility or interface over which they provide redispatch service using planning redispatch or reliability redispatch under the *pro forma* OATT; (2) a high and low redispatch cost for the month for each of these same transmission constraints; and (3) internal constraint or interface data for the month if any

planning redispatch or reliability redispatch is provided during the month, regardless of whether the transmission customer is required to reimburse the transmission provider for those exact costs. Final Rule at P 1162. FERC also requires posting of third party offers to redispatch. Final Rule at P 1005.

(f) Rollover Rights for Redispatch and Conditional Firm

- FERC states that rollover rights are appropriate for point-to-point service that is provided using planning redispatch or conditional firm options and would otherwise be eligible to for rollover rights. Final Rule at PP 1081-1082.

2. Hourly Firm Service

- While FERC initially proposed to add point-to-point hourly firm service in the NOPR, it declines to mandate it in the Final Rule. Transmission providers continue to have the option to propose the service in a 205 filing. Final Rule at P 1212.

3. Rollover Rights

- FERC revises the right of first refusal to apply to contracts that have a minimum term of five years (rather than the current one year minimum). Final Rule at P 1231.
- At the end of an initial five-year term, a transmission customer must agree to another five-year contract term or match any longer-term competing request in order to be eligible for a subsequent rollover. Final Rule at PP 1231, 1255.
- Additionally, a customer must now provide notice of whether or not it will exercise its right of first refusal no less than one year prior to the expiration date of the transmission service agreement (rather than the current 60-day period). Final Rule at P 1245.
- The only appropriate way to restrict a rollover right will continue to be based upon reasonable forecasts of native load growth or preexisting contracts that commence in the future and are included *in the initial transmission service agreement*. FERC will continue to evaluate forecasts of native load growth on a case-by-case basis. Final Rule at PP 1256-1257.
- FERC clarifies that RTOs and ISOs must submit a filing showing that their practices are consistent with, or superior to, the Final Rule's modifications, and that they do not necessarily need to create rollover rights if they do not currently exist. Final Rule at 1260.
- FERC is not changing section 1.20 of the *pro forma* OATT, which states that one year constitutes a long-term contract. Final Rule at P 1260.
- The new minimum five year/one year right of first refusal provision will become effective upon FERC acceptance of the transmission provider's coordinated and regional planning process also required by the Final Rule. Final Rule at P 1265. FERC clarified that: (1) an existing filed and accepted transmission planning process does not trigger the new rollover rules, but rather they will be triggered upon FERC acceptance of the Final Rule's required compliance filings (assuming rollover reform is applicable to the filer's

tariff service in the first instance); (2) existing contracts with a rollover right at the time of effectiveness of rollover reform may exercise their rollover based on the existing rules because it is only a rollover contract *entered into or renewed* after the effectiveness of rollover reform that must comply with the new rules. Final Rule at PP 1266-1267.

4. Modification of Receipt or Delivery Points

- FERC states that most issues related to redirect service and reform of section 22 (changes in service specifications) of the *pro forma* OATT were addressed by Order No. 676, FERC Stats. & Regs. ¶ 31,216 (2006), which adopted and incorporated into FERC's regulations the "Standards for Business Practices and Communication Protocols for Public Utilities" developed by NAESB's Wholesale Electric Quadrant ("WEQ standards"). Final Rule at P 1269.
- FERC finds that NAESB WEQ is the appropriate body for developing business practices and implementing the Commission's redirect policy. Final Rule at PP 1277-1278.
- FERC clarifies that rollover rights follow redirects, regardless of the duration of the redirect (even if, for example, the redirect is requested for a shorter period). This is consistent with FERC's prior policy that long-term customers should not have to choose between redirecting on a firm basis and maintaining rollover rights, but rather their rollover rights should be retained consistent with the long-term nature of their service. Final Rule at P 1280.
- FERC states that a redirect right does not grant a customer access to system capacity or queue position different from other customers submitting new requests for service. A redirect must be evaluated in accordance with section 17 (dealing with new requests for service) using the same system assumptions and analysis applicable to any other new request. Final Rule at P 1285.
- Although FERC found that a uniform pricing method for redirects was beyond the scope of the Final Rule, FERC noted its recent decision finding that transmission providers are not allowed to collect additional charges when a firm point-to-point customer redirects on a non-firm basis. Final Rule at 1289, citing *Midwest Independent Transmission System Operator, Inc.*, 118 FERC ¶ 61,095 at P 79-85 (2007).
- FERC finds that network customers may not redirect network service in a manner comparable to the way customers redirect point-to-point service. If necessary, a network customer may then either: (1) request to redesignate its original network resource by making a request to designate a new resource, or (2) use secondary network service to substitute a non-designated network resource for designated network resource on an as-available basis. Final Rule at P 1293.

5. Acquisition of Transmission Service

(a) Processing of Service Requests

- The *pro forma* OATT requires that transmission providers process requests for transmission service in a timely fashion. As described more fully below, FERC has created performance metrics that must be posted to each transmission provider's OASIS to ensure transparency in the processing of service requests. Final Rule at P 1296.

(1) Posting Performance Metrics

- In general, transmission providers will be required to: (1) post performance metrics for each calendar quarter within 15 days of the end of the quarter; (2) begin tracking upon the effective date of the Final Rule; (3) keep the quarterly performance metrics on their OASIS site for three calendar years; and (4) calculate the performance metrics separately for affiliates and non-affiliates. Final Rule at P 1308.

- The following set of performance metrics will be required to be posted on a quarterly basis: (1) the processing time from initial service request to offer of a system impact study agreement; (2) system impact study processing time; (3) service requests withdrawn from system impact study queue; (4) process time from completed system impact study to offer of facilities study; (5) facilities study processing time; and (6) service requests withdrawn from the facilities study queue. Final Rule at P 1310.

- Examples of information to be posted include: (1) number of system impact study agreements executed; (2) number of system impact studies completed; (3) number of requests withdrawn from the system impact study queue; (4) average cost of recommended upgrades; and (5) average time from receipt of an executed facilities study agreement to the date when completed facilities study available to customer. Final Rule at P 1310.

- The posting of performance metrics only applies to transmission delivery service requests, and not interconnection service requests. Also, RTOs and ISOs are required to post the same performance metrics. Final Rule at P 1311.

- FERC proposes that the transmission provider must file a notice with FERC in the event that the transmission provider processes more than 20 percent of non-affiliates' studies outside of the 60-day due diligence deadlines for two consecutive quarters. The transmission provider may explain any extenuating circumstances. Final Rule at P 1319.

- Following the quarter following a notification filing, the transmission provider must post: (1) the average of the employee hours expended per completed system impact study; (2) the average of the employee hours expended per completed facilities study; (3) the number of employees dedicated to processing studies. Final Rule at P 1320.

(2) Operational Penalties for Late Studies

- FERC will subject transmission providers to penalties when they fail to meet the prescribed 60-day due diligence deadlines. The transmission provider will be subject to penalties if it continues to be out of compliance with the *pro forma* OATT requirements for each of the two quarters following the notification filing. Final Rule at P 1340. A transmission provider is out of compliance if it completes 10 percent or more of non-affiliates' studies outside of the 60-day period. Final Rule at P 1340.

- The penalty will be assessed on a quarterly basis, starting with the quarter following the notification filing and continuing until the transmission provider completes at least 90 percent of all studies within 60 days after the study agreement has been executed. Final Rule at P 1340.

- For any study completed during that quarter and more than 60 days after the study agreement was executed, the penalty will equal $500 for each day the transmission provider takes to complete the study beyond 60 days. Final Rule at P 1340.

- For any study that is still pending at the end of the quarter and that has been in the study queue for more than 60 days, the penalty will equal $500 for each day the study has been in the study queue beyond 60 days. Final Rule at P 1340.

- Penalties may be waived if a transmission provider establishes that the delay is the result of factors or events beyond its control, including delays by the transmission customer. Final Rule at P 1343.

- Penalties will apply to RTOs and ISOs. Final Rule at PP 1353-1354.

- The transmission provider cannot recover penalties through rates. Final Rule at P 1357.

(3) Fee for Multiple Self-Competing Transactions

- FERC will not require transmission providers to charge a fee for duplicate requests for transmission service but does permit transmission providers that experience problems related to the submission of multiple duplicative requests to file a tariff amendment that includes a fee to deal with the problem. Final Rule at P 1365-1366.

(4) Clustering Transmission Service Request Studies

- FERC does not require transmission providers to study transmission requests in a cluster, unless the customers involved make such a request which can be reasonably accommodated. Final Rule at P 1370.

- Transmission providers must include tariff language in their compliance filing that describes how it will process a request to cluster studies and how the transmission customer's obligations will be structured when in a cluster. Final Rule at P 1371.

(5) Standardization of Business Practices for Study Queue Processing

- FERC will not amend the *pro forma* OATT to require coordination of transmission requests across multiple transmission systems. Transmission providers are required to work through NAESB to develop business practice standards for the coordination of requests across multiple transmission systems. Final Rule at P 1377.

(b) Reservation Priority

(1) Priority for Pre-Confirmed Requests

- The Final Rule gives priority to pre-confirmed non-firm point-to-point transmission service requests and short-term firm point-to-point transmission service requests. Longer duration requests will continue to have priority over shorter term requests, with pre-confirmation serving as the tie-breaker for requests of equal duration. Final Rule at P 1401.

- FERC will prohibit transmission customers from withdrawing pre-confirmed non-firm and short-term firm point-to-point requests prior to when the transmission customer is offered service or a system impact study. Final Rule at P 1403.

(2) Price as a Tie-Breaker

- FERC adopts the NOPR proposal of adding price as a tie-breaker in determining reservation queue priority when the transmission provider is willing to discount transmission service. Final Rule at P 1410.

(3) Five-Minute Window for Requests

- The Final Rule makes only one change to the current first-come, first-served policy. FERC will allow transmission providers to propose a window within which all transmission service requests the transmission provider received will be deemed to have been submitted simultaneously. Final Rule at P 1418.

6. Designation of Network Resources

(a) Qualification as a Network Resource

(1) Liquidated Damage Contracts

- FERC finds that "make whole" LD contracts (such as those found in the EEI Firm LD Product and in the WSPP Schedule C agreement) can qualify as network resources. In contrast, other LD provisions that cap penalties or set a fix-dollar amount do not qualify. Final Rule at PP 1452-54.

- An agreement that has been properly designated prior to the effective date of the Final Rule and that contains another type of LD provision will be grandfathered, only until the earlier of (1) the expiration of the current term of the agreement or (2) an indefinite termination of the agreement as a designated network resource pursuant to section 30.3 of the *pro forma* OATT. Final Rule at P 1455.

- Additionally, FERC noted that although the WSPP Schedule C agreement contained an acceptable "make whole" LD provision, the agreement would need to be revised to make clear that interruptions in generation of service in order to serve native load are prohibited for reasons other than reliability. However, despite this infirmity, FERC will not invalidate existing designations of WSPP Schedule C agreements until the earlier of (1) the expiration of the current term of the agreement or (2) redesignation of a previously designated WSPP Schedule C resource following a period of temporary or indefinite termination pursuant to sections 30.2 and 30.3 of the *pro forma* OATT. Final Rule at P 1460.

(2) Off-System Resources

- FERC requires the following information to be provided and posted on OASIS when designating an off-system resource: (1) identification of the resource as an off-system resource; (2) amount of power to which the customer has rights; (3) identification of the control area(s) from which the power will originate; (4) delivery point(s) to the transmission provider's transmission system; and (5) transmission arrangements on the external transmission system(s). Final Rule at P 1476.

- Additionally, section 29.2(v) is revised to require that the following information be provided with such designation, but such information must be masked on OASIS to prevent the release of commercially sensitive information including: (1) any operating restrictions (periods of restricted operation, maintenance schedules, minimum loading level of resource, normal operating level of resource); and (2) approximate variable generating cost ($/MWH) for redispatch computations. Final Rule at P 1476.

- FERC will not require that more specific information than the control area be provided, but if any transmission provider believes that it faces unique circumstances, it can propose changes through a 205 filing. Final Rule at P 1481.

- FERC clarified that a customer may not designate as a network resource a seller's choice power purchase agreement which is sourced by generating units internal to the transmission provider's control area. Final Rule at P 1483.

(3) Ability to Serve Native Load

- Congress did not require that LSEs be able to take transmission service without limitations of any kind in order to serve their native load; if a transmission provider has unique circumstances, it can make a section 205 filing. Final Rule at P 1493-95.

(4) General

- Firm point-to-point transmission service provided on a conditional firm basis is sufficiently firm to be used for transmission to import a designated network resource. However, designation of network resources within a control area on a conditional-firm basis will not be allowed. Final Rule at P 1503.

- The minimum time period that a transmission provider must honor for designations of new network resources should be the same as the minimum time period used for firm point-to-point service (daily). Final Rule at P 1505.

(b) Documentation for Network Resources

- FERC adopts the NOPR proposal that transmission providers continue to be responsible for verifying that third-party transmission arrangements to deliver the purchase to the transmission provider's system are firm, but that transmission providers are not responsible for verifying that the generating units and power purchase agreements that network customers designate as network resources satisfy the requirements in sections 30.1 and 30.7. Final Rule at P 1521.

- FERC adopts the proposal to require both the transmission provider's merchant function and network customers to include a statement with each application for network service or to designate a new network resource that attests, for each network resource identified, that: (1) the transmission customer owns or has committed to purchase the designated network resource and (2) the designated network resource comports with the requirements for designated network resources. Final Rule at P 1521.

- If a transmission provider or any other network customer designates a network resource that it should not, FERC will consider this an OATT violation. Final Rule at P 1523.

(c) Undesignation of Network Resources

- FERC generally adopts the NOPR proposal to continue to require network customers and the transmission provider's merchant function to undesignate network resources or portions thereof in order to make certain firm, third-party sales from those resources. Network customers may only enter into a third-party power sale from a designated network resource if the third-party power purchase agreement allows the seller to interrupt power sales to the third party in order to serve the designated network load. Such interruption must be permitted without penalty. Final Rule at P 1539.

- FERC clarifies that requests to undesignate network resources that are submitted concurrently with a request to redesignate those network resources at a specific point in time shall be considered temporary terminations and not result in forfeiture of priority. Conversely, requests to undesignate network resources submitted without any concurrent request to redesignate those network resources shall be considered a request for indefinite termination. Final Rule at PP 1540, 1544.

- FERC directs transmission providers to develop OASIS functionality and, working through NAESB, business practice standards describing the procedural requirements for submitting both temporary and indefinite terminations. Final Rule at P 1541.

- FERC clarifies that network customers are not required to file modified service agreements when resources are designated or undesignated. Final Rule at P 1581.

- FERC clarifies that firm third-party sales may be made from an undesignated portion of a network customer's network resources; however, the network customer must submit undesignations for each portion supporting the third-party sale. Final Rule at P 1582.

7. Clarifications Related to Network Service - Secondary Network Service

- Contrary to the NOPR, FERC retains the existing section 28.4, permitting use of secondary network service "to deliver energy to its Network Loads." Final Rule at P 1601.

- Secondary service must be requested in accordance with section 18 (Procedures for Arranging Non-Firm Point-to-Point Transmission Service), including the timing restrictions. Final Rule at P 1606.

- Network customers may not redirect network service in a manner comparable to the way customers redirect point-to-point service, but instead should terminate the designation of the existing resource and designate a new resource. Final Rule at P 1612.

8. Transmission Curtailments

- FERC concludes that the posting of additional curtailment information is necessary to provide transparency. Final Rule at P 1626. Transmission providers, working through NAESB, are to develop a detailed template for the posting of additional information on OASIS regarding firm transmission curtailments. Final Rule at P 1627.

- Transmission providers are not required to implement these OASIS modifications until NAESB develops appropriate standards. Postings must include all circumstances and events contributing to the need for a firm service curtailment, specific services and customers curtailed, and the duration of the curtailment. This additional, detailed template posting regarding curtailment events is in addition to OASIS postings already required by existing rules. Final Rule at P 1627.

9. Standardization of Rules and Practices

(a) Business Practices

- The Final Rule continues FERC's policy to require only those rules, standards, and practices that significantly affect transmission service to be incorporated into the transmission provider's OATT under the "rule of reason" test. Final Rule at P 1649.

- Transmission providers are to post on their public websites *all* rules, standards, and practices that relate to transmission service and provide a link to these rules, standards, and practices. Final Rule at PP 1652-53. As guidance the Final Rule references the MAPP Policies and Procedures for Transmission Operations manual. Final Rule at P 1654.

- In addition, the transmission provider must post on its public website a statement of the process by which the provider will amend its rules, standards, and practices, including a mechanism to provide reasonable notice of any proposed changes to a posted business practice and the respective effective date of such change. Final Rule at P 1655.

(b) Credit Standards

- The Final Rule amends the *pro forma* OATT to include Attachment L describing the transmission provider's basic credit standards. It will include the quantitative and qualitative criteria to be utilized by the transmission provider to determine the level of credit extended to customers, including procedures to determine levels of secured and unsecured credit, types of acceptable collateral and security, procedures for providing notice of changes in credit levels, a procedure for providing customers written explanations of changes in credit determinations, and a reasonable opportunity for customers to post additional collateral or cure a lack of creditworthiness. Final Rule at PP 1656-57. Attachment L includes summary information about credit procedures and the Final Rule clarifies that more detailed credit procedures, metrics, or other information that relates to the provision of transmission service can be provided on the transmission provider's website. Final Rule at P 1658.

10. OATT Definitions

- The Final Rule adopts the OATT definition of "affiliate" proposed by the NOPR, with two clarifications. First, FERC clarifies that there is no corporate affiliation between G&T cooperatives and member distribution cooperatives. Final Rule at P 1682. Second, the Final Rule states that the affiliation of a merchant to a transmission provider does not establish an affiliation between such merchant and an RTO or ISO that has operational control over the transmission facilities of the transmission provider. Final Rule at P 1683.

- FERC incorporates the definition of reliable operation from FPA section 215 into the definition of "good utility practice" in the *pro forma* OATT. Final Rule at P 1687.

- The Final Rule creates a definition of "non-firm sale" to clarify the treatment of such sales under section 30.4 of the *pro forma* OATT. As provided in the *pro forma* OATT, network customers may use network resources for third party sales only if the sale is on a non-firm basis. Final Rule at P 1692.

- The Final Rule adopts the NOPR proposed definition of "pre-confirmed application" in order to implement the reforms adopted regarding the priority of transmission service requests. Final Rule at P 1695.

E. Enforcement

- FERC's enforcement program will include: (1) operational audits (as in past OATT compliance audits); (2) audits that can be random or targeted at specific entities or compliance with specific provisions; and (3) staff discretion as to audited entities and subject matters. Final Rule at P 1718.
- Although it does not eliminate the possibility of an audit, transmission providers should designate employees as compliance officers for the OATT or conduct third-party audits where appropriate. Final Rule at P 1718.
- FERC does not prescribe specific penalties, develop formulas for different violations, or create "safe harbors." Rather, penalty assessments will depend on a review of all applicable mitigating factors and the specific circumstances surrounding each violation. FERC also rejects automatic exemptions from civil penalties for violations by certain types of entities, such as non-profit RTOs. Final Rule at PP 1730-1732.
- FERC states that it will not consider an entity to be uncooperative with audit staff if the entity appropriately asserts the attorney-client privilege. FERC notes, however, there is a difference between "cooperation" (required by the FPA) and "exemplary" cooperation that ends wrongful conduct quickly. Final Rule at PP 1733-1734.
- FERC will revoke an entity's market-based rate authority in response to an OATT violation only upon a finding of specific factual nexus between the violation and the entity's market-based rate authority. It is FERC's burden to show the factual nexus, and the decision will be made on a case-by-case basis. FERC notes, however, that it has discretion to fashion remedies for OATT violations that relate to the violator's market-based rate authority in instances which it does not find a factual nexus justifying revocation of the market-based rate authority. Final Rule at PP 1743-1745.
- FERC does not adopt its NOPR proposal to revoke the market-based rate authority of each affiliate of a transmission provider that loses its market-based rate authority within a particular market as a result of an OATT violation. Rather, such affiliates will have an opportunity to overcome a rebuttable presumption that they should lose their market-based rate authority in such circumstances. Final Rule at PP 1746-1748.
- The Commission will use a case-by-case approach to considering whether OATT violations may constitute market manipulation. Final Rule at P 1751

IV. CORE ELEMENTS OF ORDER NO. 888 THAT ARE RETAINED

A. Federal/State Jurisdiction

- The Final Rule retains the existing jurisdictional divide established in Order No. 888 – FERC would have exclusive jurisdiction over unbundled retail transmission service but would not exercise jurisdiction over bundled retail transmission. Final Rule at P 94.

B. Native Load Protection

- The Final Rule concludes that the native load priority established in Order No. 888 is appropriate and is consistent with FPA section 217, which protects the transmission rights of entities with service obligations to end-users or a distribution utility to the extent required to meet their service obligations. Final Rule at P 107.

C. The Types of Transmission Service Offered

- The Final Rule concludes that network and point-to-point services are the appropriate base-line service offerings, and will not mandate that transmission providers adopt new service offerings such as network contract demand service. Final Rule at P 115.

D. Functional Unbundling

- As proposed in the NOPR, the Final Rule continues to require functional, rather than corporate or structural, unbundling. Final Rule at PP 122-123.

E. Other Unchanged Provisions

1. Behind the Meter Generation

- FERC will not require transmission providers to allow netting of behind the meter generation against transmission service charges to the extent customers do not rely on the transmission system to meet their energy needs. Instead, FERC will continue to review alternative transmission provider proposals for behind the meter generation treatment on a case-by-case basis. Final Rule at P 1619.

2. Liability and Indemnification

(a) Force Majeure

- The Final Rule retains language utilizing "all reasonable efforts" in the OATT force majeure provision and notes that the provision applies to both transmission providers and customers. Final Rule at 1664.

(b) Indemnification/Limitation of Liability

- The Final Rule retains the existing liability protections in the *pro forma* OATT, rejecting calls by certain industry participants to adopt broader customer indemnification obligations and declining to adopt a gross negligence standard of liability for transmission providers other than for ISOs and RTOs. Final Rule at PP 1671-72.

3. Other Provisions

The following sections are not modified by the Final Rule:

- Section 5 on Local Furnishing Bonds,
- Section 7 on billing and payment,
- Section 8 on accounting for the Transmission Provider's use of the tariff,
- Section 9 on regulatory filings,
- Section 10 on Force Majeure and indemnification,
- Section 12 on dispute resolution,
- Section 20 on procedures if the Transmission Provider is unable to complete new transmission facilities,
- Section 21 on transmission and construction services on the systems of other utilities,
- Section 22 on changes in service specifications,
- Section 24 on metering,
- Section 25 on compensation,
- Section 26 on stranded cost recovery,
- Section 33 on load shedding and curtailment,
- Section 34 on rates and charges,
- Schedule 1 on scheduling, system control and dispatch service,
- Schedule 7 in point-to-point transmission service, and
- Schedule 8 on non-firm service.

V. COMPLIANCE DEADLINES

Below is the Final Rule's chart of major compliance deadlines,[10] with a few additions. For a more detailed description of compliance obligations, please refer to the Final Rule paragraph number in the right-hand column.

Deadline (days after publication in Fed. Reg.)	Compliance Action	Final Rule Paragraph #
Upon Effective date	Begin tracking performance metrics for quarterly postings	P 1308

[10] *See* Final Rule at pages 1061-62.

Deadline (days after publication in Fed. Reg.)	Compliance Action	Final Rule Paragraph #
30	Optional implementation FPA section 205 filings allowing transmission providers to propose previously approved variations from the *pro forma* OATT that have been affected by *pro forma* OATT Final Rule reforms to remain in effect subject to a demonstration that such variations continue to be consistent with or superior to the revised Final Rule *pro forma* OATT (non RTO/ISO transmission providers). Such optional filings must request a 90 day effective date to facilitate Commission review under section 205.	P 139
60	Non-ISO/RTO transmission providers submit FPA section 206 filings that contain the non-rate terms and conditions set forth in Final Rule. These filings need only contain the revised provisions adopted in the Final Rule. Transmission providers utilizing the optional implementation FPA section 205 filing described above, need only submit tariff sheets necessary to implement the remaining modifications required under the Final Rule, i.e., modifications related to tariff provisions that did not implicate previously-approved variations.	P 135
75	Transmission providers must post a "strawman" proposal for compliance with each of the nine planning principles adopted in the Final Rule. This may be posted on the transmission provider's website or its OASIS site.	P 443
90	NERC/NAESB status report and work plan for completion of ATC related business practices and standards.	P 223
90	NAESB status report and work plan for completion of OASIS functionality or uniform business practices (other than those related to ATC).	P 141
120	Transmission providers must submit redesigned transmission charges that reflect the Capacity Benefit Margin set-aside through a limited issue section 205 rate filing as part of their initial ATC related compliance filings	P 263
180	Submit compliance filings with Attachment C (ATC) of the *pro forma* OATT	P 140
180	Transmission providers must implement regional mechanisms and business practices for the provision of conditional firm service.	P 1046
210	ISOs and RTOs, and transmission providers located within an ISO/RTO footprint, must submit FPA section 206 filings that contain the non-rate terms and conditions set forth in the Final Rule. These filings need only contain the revised provisions adopted in the Final Rule or a demonstration that previously approved variations continue to be consistent with or superior to the revised *pro forma* OATT.	P 157 P 161
210	Submit compliance filings with Attachment K (Planning) of the *pro forma* OATT or RTOs and ISOs file a demonstration that their planning processes are consistent with or superior to the planning principles in the Final Rule	P 140 P 442
270	Public utilities must work through NERC to modify the ATC-related reliability standards	P 223
360	Public utilities must work through NAESB to develop business practices that complement NERC's new reliability standards	P 223
N/A	Transmission providers must file a revised Attachment C to incorporate any changes to NERC's and NAESB's reliability and business practice standards to achieve consistency in ATC within 60 days of completion of the NERC and NAESB processes.	P 325
N/A	After the submission of FPA section 206 compliance filings, transmission providers may submit FPA section 205 filings proposing rates for the services provided for in the tariff, as well as non-rate terms and conditions that differ from those set forth in the Final Rule if those provisions are "consistent with or superior to" the *pro forma* OATT.	P 135

APPENDIX A

SUMMARY OF SIGNIFICANT MODIFICATIONS TO THE CURRENTLY EFFECTIVE PRO FORMA OATT

ORDER NO. 890:
SUMMARY OF SIGNIFICANT MODIFICATIONS
TO THE CURRENTLY EFFECTIVE PRO FORMA OATT

MODIFICATION	ORIGINAL SHEET NO.
Added definition for "affiliate."	10
Added reference to FPA Section 215(a)(4) to definition of "good utility practice."	14
Added definition of "non-firm sale."	18
Added definition of "pre-confirmed application."	20
Added definition for "system condition."	21-22
Added clarification regarding right of first refusal rights for existing service agreements once a transmission provider's Attachment K is accepted.	25
Discussion of Ancillary Services amended to include references to non-generation sources of reactive and voltage control.	25
Modified Ancillary Services discussion to provide that a transmission customer that exceeds its firm reserved capacity is required to pay for Ancillary Services related to such transmission.	26
Reference made to Generator Imbalance Service and Schedule 9 details of such service.	28
New provision added to require transmission provider to post all rules, standards, and practices related to transmission service on its public website and procedures to be used to institute changes to these rules, standards, and practices.	29-30
Expanded the number of transmission customers subject to the OATT's reciprocity requirements to those that take transmission service from RTOs, ISOs, and other regional entities.	32
Removed section regarding creditworthiness standards in the body of the OATT and replaced the section with reference to Attachment L.	37-38
Provided greater clarification of service priority among short-term firm point-to-point transmission customers.	41-42
Provided greater clarification of service priority among short and long-term service customers.	42-43
Modified the discussion of service agreements to provide that eligible customers that receive service will be deemed to have executed a service agreement, provides for conditional curtailment provisions in service agreements,	44-45

MODIFICATION	ORIGINAL SHEET NO.
Provided that eligible customers may take service from the transmission provider if they agree either to compensate transmission providers for necessary transmission additions or subject to biennial reassessment of redispatch requirements.	46
Provided additional priorities for curtailment of long-term firm point-to-point service.	47
Addressed priority of pre-confirmed applications.	52
Added reference to the new transmission planning requirements in Attachment K.	60
Required transmission providers to utilize due diligence to accommodate firm point-to-point transmission service via redispatch or conditional curtailment procedures, where appropriate.	60-62
Provided that transmission customers must provide the data required by Attachment K's transmission planning process in order to receive firm point-to-point service.	63
Required transmission customer applications to include whether the customer commits to a pre-confirmed request and information required for transmission planning purposes under Attachment K.	67
Regarding extensions for commencement of service to an eligible customer, provided for withdrawal of applications where a request for extension is pending and a non-refundable reservation fee is not timely paid.	71
Required transmission customer applications for non-firm point-to-point service to include whether the customer commits to a pre-confirmed request.	73
Provided option to eligible customer to forego study of redispatch or conditional curtailment as part of a system impact study.	75
Provided greater detail regarding content of system impact studies, including redispatch.	77-78
Provided penalties and procedures related to a transmission provider's failure to timely complete system impact studies and facility studies.	82-84
Modified procedures for assignment of transmission service rights, including timely execution by assignee of a service agreement.	90-91
Provided that assignments of transmission service rights must be done over OASIS.	92
Included reference to Attachment K transmission planning process in discussion of transmission provider responsibilities.	95-96

MODIFICATION	ORIGINAL SHEET NO.
Clarified preconditions to provision of secondary service.	97
Provided that the transmission provider will establish stated penalties and charges for network service customers that utilize network integration transmission service to permit a wholesale sale not serving network load.	98
Provided for designation and data in applications related to off-system network resources.	102-103
Required applications for network service to include a certification and additional data required by Attachment K.	104-105
Imposed new requirements for a network customer to designate a network resource.	107-108
Provided procedures by which a network customer may terminate the designation of network resources, including temporary termination.	108-110
Addressed scheduling of network resources not physically connected to the transmission provider's transmission system.	110-111
Provided greater detail regarding conditions under which transmission customer will receive credits for integrated transmission facilities.	113
Required network customers to provide Attachment K information in its annual load and resource update.	116
Specified that failure to complete facilities studies and system impact studies under Part 3 of the OATT utilize the same penalties and procedures as outlined in Part 2.	121
Edited Schedules 2, 3, 4, 5, 6, and 9 to provide for possible use of non-generation resources to provide certain ancillary services.	131, 133, 134, 137, 138, 143
Edited Schedule 4 to provide procedures regarding imbalance services and calculation of related charges.	134-135
Added Schedule 9 regarding generator imbalance service.	143-145
Added Attachment A-1 to standard *pro forma* long-term firm form of service agreement related to the assignment of transmission service.	150-153
Added Attachment C regarding methodologies to calculate ATC.	156-157
Added Attachment J regarding parallel flows.	164
Added Attachment K to formalize procedures to be used in the transmission provider's transmission planning process.	165-166
Added Attachment L regarding creditworthiness evaluations and credit determination procedures.	167

APPENDIX B

SUMMARY OF SIGNIFICANT MODIFICATIONS TO PRO FORMA OATT PROPOSED IN THE NOPR

ORDER NO. 890:
SUMMARY OF SIGNIFICANT MODIFICATIONS
TO PRO FORMA OATT PROPOSED IN THE NOPR

MODIFICATION	ORIGINAL SHEET NO.
Deleted definition of "economy energy."	12
Added definition for "system condition."	21-22
Discussion of Ancillary Services amended to include references to non-generation sources of reactive and voltage control.	25
Modified Ancillary Services discussion to provide that a transmission customer that exceeds its firm reserved capacity is required to pay for Ancillary Services related to such transmission.	26
Reference made to Generator Imbalance Service and Schedule 9 details of such service.	28
New provision added to require transmission provider to post all rules, standards, and practices related to transmission service on its public website and procedures to be used to institute changes to these rules, standards, and practices.	29-30
Expanded the number of transmission customers subject to the OATT's reciprocity requirements to those that take transmission service from RTOs, ISOs, and other regional entities.	32
Changed the minimum term for firm point-to-point transmission service from one hour to one day.	40
Deleted references to pre-confirmed applications for service for long-term firm point-to-point service.	41
Provided greater clarification of service priority among short-term firm point-to-point transmission customers.	41
Provided greater clarification of service priority among short and long-term service customers.	42-43
Modified the discussion of service agreements to provide that eligible customers that receive service will be deemed to have executed a service agreement. Provided for conditional curtailment provisions in service agreements.	44-45
Provided additional priorities for curtailment of long-term firm point-to-point service.	47
Required transmission providers to utilize due diligence to accommodate firm point-to-point transmission service via redispatch or conditional curtailment procedures, where appropriate.	60-61

MODIFICATION	ORIGINAL SHEET NO.
Regarding extensions for commencement of service to an eligible customer, provides for withdrawal of applications where a request for extension is pending and a non-refundable reservation fee is not timely paid.	71
Provided option to eligible customer to forego study of redispatch or conditional curtailment as part of a system impact study.	75
Provided greater detail regarding content of system impact studies, including redispatch.	77-78
Modified procedures for assignment of transmission service rights, including timely execution by assignee of a service agreement.	90-91
Provided that assignments of transmission service rights must be done over OASIS.	92
Provided that the transmission provider will establish stated penalties and charges for network service customers that utilize network integration transmission service to permit a wholesale sale not serving network load.	98
Provided for designation and data in applications related to off-system network resources.	102-103
Provided procedures by which a network customer may terminate the designation of network resources, including temporary termination.	108-110
Edited Schedules 2, 3, 4, 5, 6, and 9 to provide for possible use of non-generation resources to provide certain ancillary services.	131, 133, 134, 137, 138, 143
Edited Schedules 4 and 9 to provide procedures regarding imbalance services and calculation of related charges.	134-135, 143-145
Added Attachment A-1 to standard *pro forma* long-term firm form of service agreement related to the assignment of transmission service.	150-154
Modified Attachment C regarding methodologies to calculate ATC.	156-157
Revised Attachment K to formalize procedures to be used in the transmission provider's transmission planning process.	165-166

Attachment 2c1

North American Energy Standards Board

1301 Fannin, Suite 2350, Houston, Texas 77002
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Home Page: www.naesb.org

NERC NAESB Template
Procedure for Joint Standards Development and Coordination
Prepared as of 2-22-06

Principles & Assumptions:	• The joint standards should be readily and easily available to all industry participants required to follow them. • The jointly developed standard(s) should clearly distinguish components within it as either being reliability-related or business practices-related. A jointly developed standard can be a "two-part" standard clearly identifying that it contains (a) separate reliability requirements and (b) separate business practices, but such requirements cannot be both reliability and business practice requirements. • The procedures followed for joint development will comport with the existing standards development procedures certified by ANSI for both organizations.
Goals & Objectives:	• The joint development efforts are closely coordinated within the procedures defined and approved for NERC and NAESB. • The participation within the joint development is balanced between NERC and NAESB to ensure an equitable outcome. • The procedures should not be overly bureaucratic to discourage the NERC and NAESB volunteers from participation. They should be written to allow the volunteers to focus on the development of standards, rather than interpretations of the procedures. • The participants should be committed to the process, demonstrating a willingness to reach consensus and provided with the ability to make decisions from the organizations they represent. • The executive management of NERC and NAESB should be actively involved in resolution of disputes and in providing guidance to support consensus building between the two organizations.
Key Differences between reliability standards and business practices:	• Reliability standards are directed to the continuous operation of the power grid, and address the performance, adequacy and security of the bulk electric system. • Business practices are focused on the transparency of the power market and support a strong and diverse market. Much of the business practices are directed toward streamlining commercial transactions and the information exchanged to effect those commercial transactions between trading partners. • As noted in Appendix A of the MOU, except as required to achieve specific reliability objectives, the functions identified in the functional model diagrams as “generator” whether merchant or load-affiliated), “purchasing-selling entity,” “load-serving entity,” “market operator,” “customer aggregator,” and certain of the relationships and information flows of transmission service provider,” “transmission owner,” and “transmission operator” are associated with how wholesale electric business practices and electronic communication protocols are developed for use by market participants.

NERC NAESB Template
Procedure for Joint Standards Development and Coordination
Prepared as of 2-22-06

	Additionally, market criteria such as product or service definitions, specifications, and compensation; prerequisites for participation in market and identification of costs and funding obligations; arrangements for product and service delivery to customers; creditworthiness requirements; market-related business practices; market settlement practices; and communication protocols in support of market criteria should be considered. Standards development proposals applicable to those functions and to the relationships and information flows among those functions normally would be assigned to NAESB, unless there is a specific reliability objective to be addressed to one of these functions. • As noted in Appendix A of the MOU, in general, the functions identified in the functional model diagrams as "reliability authority," "balancing authority," "interchange authority," "compliance monitor," "NERC," and certain of the relationships and information flows of "transmission service provider," "transmission owner," and "transmission operator" are associated with the reliable operation of the bulk power system. Standards development proposals applicable to those functions and to the relationships and information flows among those functions normally would be assigned to NERC, unless there is a specific business practice objective to be addressed to one of these functions. • Business practices are forwarded to the FERC, and the process for making the standards mandatory to the utilities falls under the Federal Power Act. If the FERC chooses, the standards may be included in a notice of proposed rule-making, followed by a comment period, possibly followed by a final order, additional comments and an order on rehearing. The Commission ensures that the standards are followed by the jurisdictional entities and sets the compliance terms. • Reliability standards will follow the rules of the Electric Reliability Organization (ERO) and fall under the Energy Policy Act of 2005. The ERO sets the performance measures, terms for compliance and penalties for non-compliance and as such the reliability standards should be clearly measurable. FERC must approve the reliability standards before they take effect. The reliability standards apply to a broader audience than that of business practices mandated by the FERC.
Constraints and Other Considerations:	• NERC and NAESB executive management have agreed that a revenue neutral solution to provide for joint publication of standards is needed and should be achievable. The NERC and NAESB executive management should make the decision if joint publication is needed. • The template described herein for a joint standards development and coordination process is a standalone agreement between NERC and NAESB, drafted by the senior executives of each group. • The NERC and NAESB senior executives responsible for the coordination may choose to form a separate group to address issues brought forward that needed joint guidance or joint resolution when consensus of the joint development group was not achieved.

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NERC NAESB Template
Procedure for Joint Standards Development and Coordination
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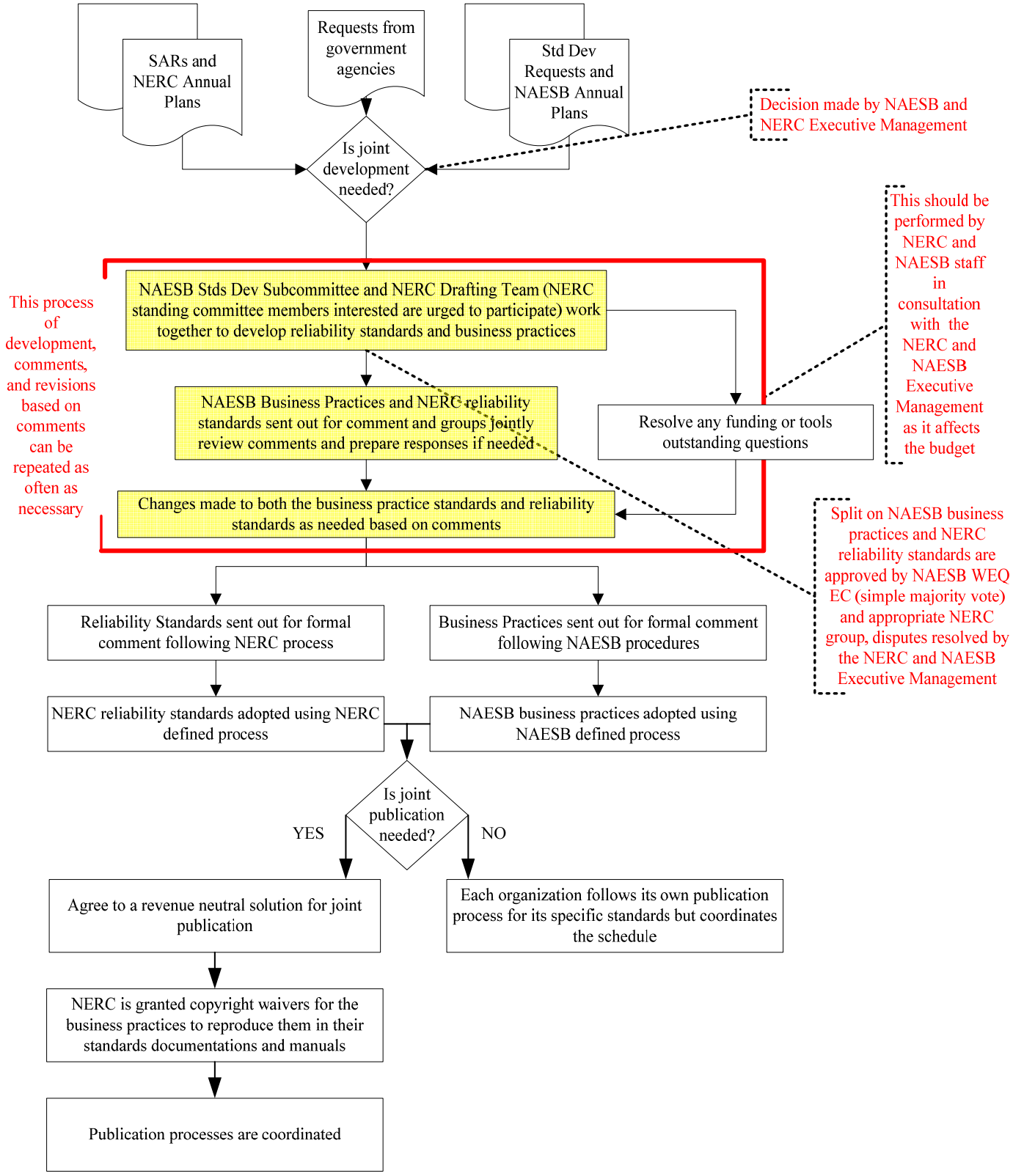
Process Description:	• After a request or SAR is assigned to NAESB or NERC, the senior executives of the two groups determine if joint development is needed. • If it is needed, the request or SAR is assigned to the appropriate NAESB standards development group and the NERC drafting team. The two groups hold joint meetings and jointly determine the split of standards into reliability standards and business practices. • The split is forwarded to the WEQ EC for approval and the appropriate committee within NERC for approval. The groups still continue to meet jointly and pursue development while this approval is being sought. This step should not cause delay in development. • Once standards have been drafted, the standards may be posted for one or more rounds of comments and responses until the joint group has reached the determination that a broad general industry perspective has been achieved and the standards are ready for vote. • Before the standards are sent out for adoption, the NERC office and the NAESB office should determine if tools or other software are needed, or if those tools or software in place need modifications. If so, the two offices will be required to make a determination if the creation of tools or software or changes to existing tools or software are technically feasible and within the financial framework of the organizations. If they are not feasible or fundable, the senior management of the two organizations shall be requested to determine a course of action regarding tools or software. • The standards then follow both the NERC procedure (for the standards deemed reliability) and the NAESB procedure (for standards deemed business practices) for adoption. For ease of viewing by users during development, the reliability standards may show the associated business practices for reference and the business practices may show the associated reliability standards for reference. However, the reliability standards and business practices shall remain separate and shall be approved through each respective process. • Once adopted, the senior executives of both NERC and NAESB shall determine if joint publication is needed to facilitate use by stakeholders. If so, the publication should clearly distinguish the reliability standards from the business practices in one document. NERC and NAESB senior executives with responsibility for the legal aspects and financial aspects of the two organizations will have previously reached a revenue neutral solution on the joint publication. • The business practices standards will be filed with the FERC and the reliability standards will follow the procedures outlined for the ERO. The filings may be joint, but should clearly identify each standard as either a business practice or reliability standard as they are to be treated differently by FERC and will apply to a different

NERC NAESB Template
Procedure for Joint Standards Development and Coordination
Prepared as of 2-22-06

	jurisdiction. • Should there be a dispute or an inability to reach a joint agreement during any part of the procedure outlined, the senior management of NERC and NAESB will be approached for guidance and resolution.
Special Considerations on Outstanding Issues:	• This process demonstrates to the NAESB WEQ Board of Directors that sufficient coordination between the two organizations is in place so that the TLR business practices may proceed on to the ratification process. After ratification, the standards will not be forwarded to the FERC in a filing until the two organizations have used the joint development process to ensure that both the reliability standards and business practices are consistent. • The FERC may monitor and could provide input and guidance during the joint development efforts. • A joint development and coordination process as outlined above would preclude the need for the Joint Interface Committee to make an assignment of each proposed standard, as the reliability standards and business practices would be developed in concert while avoiding duplication of effort and conflicting results.


SARs and NERC Annual Plans
Requests from government agencies
Std Dev Requests and NAESB Annual Plans
Decision made by NAESB and NERC Executive Management
Is joint development needed?
This should be performed by NERC and NAESB staff in consultation with the NERC and NAESB Executive Management as it affects the budget
This process of development, comments, and revisions based on comments can be repeated as often as necessary
NAESB Stds Dev Subcommittee and NERC Drafting Team (NERC standing committee members interested are urged to participate) work together to develop reliability standards and business practices
NAESB Business Practices and NERC reliability standards sent out for comment and groups jointly review comments and prepare responses if needed
Resolve any funding or tools outstanding questions
Changes made to both the business practice standards and reliability standards as needed based on comments
Split on NAESB business practices and NERC reliability standards are approved by NAESB WEQ EC (simple majority vote) and appropriate NERC group, disputes resolved by the NERC and NAESB Executive Management
Reliability Standards sent out for formal comment following NERC process
Business Practices sent out for formal comment following NAESB procedures
NERC reliability standards adopted using NERC defined process
NAESB business practices adopted using NAESB defined process
Is joint publication needed?
YES
NO
Agree to a revenue neutral solution for joint publication
Each organization follows its own publication process for its specific standards but coordinates the schedule
NERC is granted copyright waivers for the business practices to reproduce them in their standards documentations and manuals
Publication processes are coordinated

Attachment 2c2

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

Princeton Forrestal Village, 116-390 Village Boulevard, Princeton, New Jersey 08540-5731

Supplement to NERC-NAESB Procedure for Joint Standards Development and Coordination

Draft 1.2 — April 13, 2006

Reference: Procedure for Joint Standards Development and Coordination February 22, 2006

Purpose of this Supplement

This supplement to the NERC—NAESB Procedure for Joint Standards Development and Coordination (**Attachment 1**) is intended to aid the two organizations and their stakeholders in implementing the procedure. The supplement provides additional information and clarifies the intended use of the procedure.

Need for a Joint Standard Development Procedure

NERC and NAESB, along with the ISO/RTO Council (IRC), coordinate the development of standards through a revised and restated memorandum of understanding (MOU). This coordination is intended to "avoid overlap and duplication of effort in the activities of the three organizations by distinguishing the development, proposal and implementation of ISO and RTO policy from the setting of reliability standards or business practice standards."

The mechanism for coordination has been provided through the Joint Interface Committee (JIC), comprising balanced representation from the three organizations. Coordination has also been provided, in some cases, on an ad hoc basis through informal relationships between NERC and NAESB technical groups. The primary role of the JIC has been:

- to provide consultative review of annual work plans of the three organizations, as related to the development of standards for the bulk power system and wholesale electricity markets; and
- to assign the development of proposed standards to NERC or to NAESB.

Historically, the JIC has assigned a proposed standard to NERC or NAESB based on whether the JIC viewed the content as either majority reliability or majority business practice. This approach works well when there is a clear distinction between reliability requirements and business practices. However, this decision is more difficult when the reliability and business practice

components are intricately entwined within a proposed standard. Experience has shown that forcing a split of such a standard or assigning it to only one of the organizations is not optimal.

With NERC's application to become the electric reliability organization (ERO) for North America, NERC's reliability standards have been filed with the U.S. Federal Energy Regulatory Commission and governmental agencies in Canada for the purpose of making the standards mandatory for all bulk power system owners, operators, and users. NERC must have a complete set of standards necessary to protect the reliability of the bulk power system. Any reliability components assigned for development by NAESB would not be enforceable under the authorities delegated to the ERO and the regional entities. Similarly, NAESB files its business practice standards with FERC. The Commission can elect to make these business practices mandatory for public utilities. With these differences in the use and jurisdiction of the standards, it is important that each organization be able to develop a complete set of standards without being encumbered by the work of the other organization.

The conclusion is that when separating standards into reliability or business practice is difficult and potentially detrimental, a preferred approach is to develop the standards jointly. Joint development enables technical experts to separate the reliability and business practice components at the working level with a much finer granularity compared to simply splitting the standard or assigning it to only one organization.

Joint Development Process

The joint development procedure establishes a method for coordinating the development of reliability standards and business practices. The method involves developing both a reliability standard and a business practice standard in a single, coordinated work effort. A team of experts, balanced between NERC and NAESB stakeholders, works together to draft both the reliability and business practice components. The team may split into subgroups periodically to work on reliability or business practice components, but returns back to the joint group for coordination, review, and editing of the resulting drafts prepared by the subgroups.

The reliability components drafted by the joint team are developed and approved through the NERC reliability standards development process. That means a Standard Authorization Request (SAR) is developed, the SAR and drafts of the reliability standard are subject to stakeholder review and comment; and stakeholders vote to approve the standard. The business practice components go through the NAESB standards development process, as well, including review and comment by interested parties and approval by the Executive Committee and ratification by the membership. To the extent practical, the joint team coordinates the timing of the proposed standards as they move through the respective processes to completion.

Thus, the development of joint standards does not alter or affect either organization's process. The reliability components are approved through the NERC process as reliability standards and the companion business practices are approved through the NAESB process.

Results Produced by Joint Development Procedure

The final product of the joint development effort is viewed in two ways. First, NERC and NAESB may agree to joint publication of a common document containing both the reliability standard and business practice standard as complementary sections. In most cases, joint publication would be preferred, as it would have the benefit of facilitating ease of use by those who just need to "follow the rules" and prefer not to look in two places to find the rules.

The joint development procedure refers to "revenue neutral" publication. This means that if either organization derives revenues from the publication of its standards, the two organizations will, before joint publication occurs, reach a mutually acceptable arrangement that avoids or mitigates the potential loss of revenue for that organization. Without such an agreement, the respective standards would not be published jointly.

In terms of the impact of the standards, the joint effort produces separate reliability and business practice standards that may be applied through separate jurisdictional procedures. For example, the reliability standard portion can be filed as a reliability standard and made enforceable for bulk power system owners, operators, and users in North America. NAESB can continue its practice of filing business practice standards for adoption by FERC as mandatory for public utilities in the U.S. Despite joint development and the possibility of joint publication, the reliability standards and business practice standards remain distinct and separate with regard to their impacts on affected entities.

Figure 1 shows a simple conceptual representation of this "separate but joint" product.

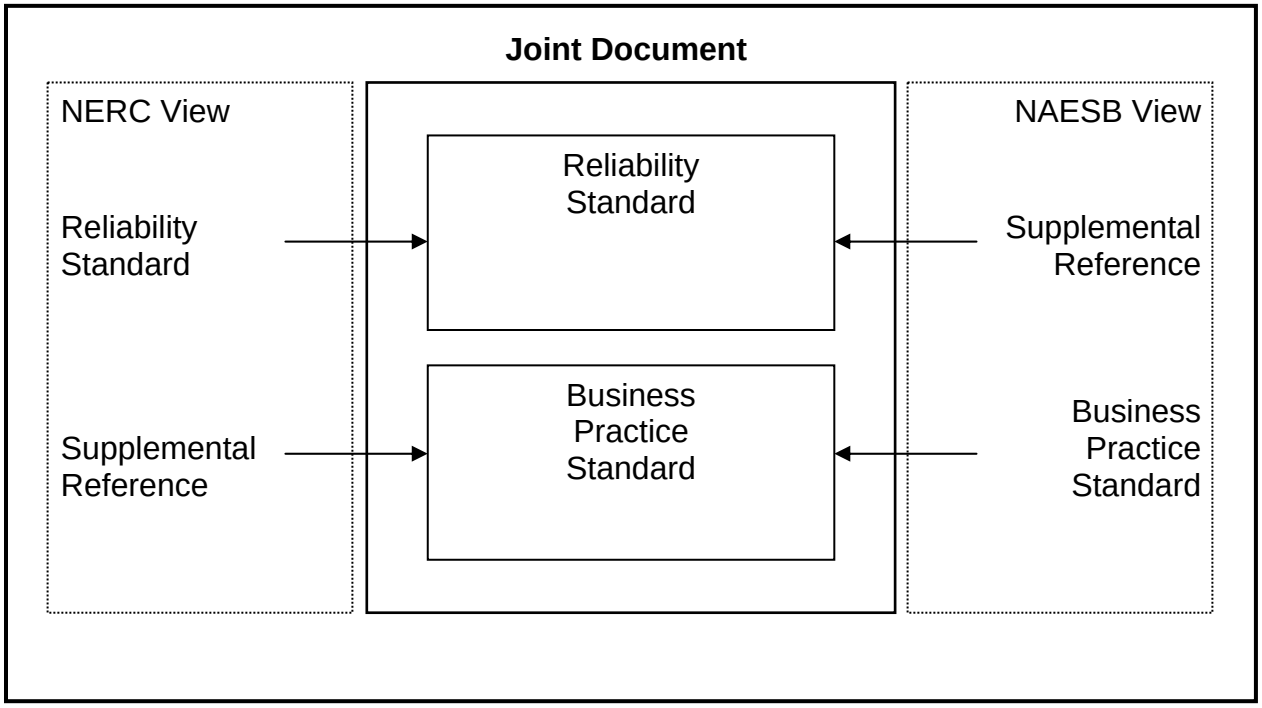


Figure 1 — Concept of Separate but Joint Standards

Role of Executive Managements of the Organizations

The joint development procedure refers several times to actions by "executive management" of the NERC and NAESB organizations. The phrase "executive management" means a combination of executive staff and relevant stakeholder executives working in consultation, in accordance with the established procedures and stakeholder relationships of each respective organization. For NERC, the stakeholder executives are the Executive Committee of the Standards Authorization Committee, and may also include executives of other committees as appropriate based on the subject of the proposed standard. In NAESB, stakeholder executives are the officers of the Board of Directors, and may also include board committees or officers and other leadership from the Executive Committee as determined by the board officers.

Role of the Joint Interface Committee

Consistent with the MOU, the historical role of the JIC has been to provide consultative review of annual work plans and to assign standards to NERC or NAESB for development. A joint development project achieves the goal of coordinating standards development through another method. Therefore, there is no need in the case of joint development for the step of assigning the standard to NERC or NAESB.

The joint development procedure anticipates that NERC and NAESB executive managements will work closely together to identify proposed standards that would be more effectively and efficiently developed in a joint effort than in one organization. The executive managements of both organizations would present the recommendation for a joint project to the JIC for consultative review, and will take into consideration any comments made by the JIC. Once the executive managements of the organizations make a final determination to begin a joint project, stakeholder and staff resources will be assigned through the regular established procedures of the respective organizations.

The consultative review of the JIC is analogous to the review the JIC provides for the annual standards development work plans. This role of the JIC in performing a consultative review does not change the MOU, nor does it extend the responsibilities of the JIC.

Development of Tools

The joint development procedure refers to decision-making regarding the development of tools necessary to implement the standards. Any decision by any party to the MOU to develop tools would be expected to be made through the business plan and budget approval process of the respective organization. Nothing in the joint development procedure would obligate any party to the MOU to develop tools to support or implement standards.

Attachment 3a

Standard MOD-003-1 — Procedure to resolve comments and questions regarding ATC and AFC Methodologies and Values

A. Introduction

1. **Title:** Procedure to resolve comments and questions regarding ATC and AFC Methodologies and Values

2. **Number:** MOD-003-1

3. **Purpose:** To promote the communication of Transmission Service Provider calculation methodologies and values used for calculating Available Transfer Capability (ATC), and Available Flowgate Capability (AFC) among Transmission Customers.

Comment: NAESB comment that this should be business practice; it only addresses and penalizes failures to communicate. Communication is typically a NAESB business practice development area. Failure to communicate to does not affect reliability of the system.

Comment: talking about values that go into the calculation or the actual calculated ATC/AFC value itself? Need clarification on this item.

4. **Applicability:**

4.1. Each Transmission Service Provider

4.1.1 Entity Limitations. Transmission Service Providers that are not required to have an OASIS may publish on a publicly available Web site the information discussed in the requirements and measurements sections of this standard.

Comment: are there non-jurisdictional entities that 4.1.1 would apply to?

5. **Effective Date:** t.b.d.

B. Requirements

R1. The Transmission Service Provider shall post on OASIS the telephone number and email address of a contact person to whom concerns are to be addressed regarding the AFC and the ATC methodologies and their associated numeric values. [Risk factor: t.b.d]

NAESB is concerned about having two methods of contacting TSPs

Comment: The person who knows the methodology is not necessarily the same individual who contributes to the day to day ATC/AFC posting; posting of one e-mail address will not necessarily be sufficient for answering all questions.Comment: if expected to post new names with shift changes will be administrative burden for TP.

R2. Each Transmission Service Provider shall create on its OASIS an electronic data input field form for the specific purpose of receiving and responding to queries regarding the AFC and the ATC methodologies and their associated numeric values. [Risk factor: t.b.d]

Comment: Need clarification whether standard would allow submission of question through e-mail as provided in R1 or only through OASIS posting as set forth in R2?

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NAESB thinks that th a NAESB business pr

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Comment: If questions are accepted through e-mail are those also required to be posted on OASIS?

R3. Subject to commercial confidentiality constraints, within one week of the electronic receipt of a query received via the aforementioned field form in R2, the Transmission Service Provider shall post on OASIS an answer to the received query. [Risk factor: t.b.d]

NAESB will be asked to create a template(s) for OASIS postings for R1 – R3.

Comment: If NAESB develops template for posting and is not referenced in the NERC standard, does that mean this requirement lends itself to being adopted by NAESB?

Comment: R3 treats all queries equally. All queries must be responded to within a week. Some may take longer to respond to due to the nature of the query. Limitation of 1 week appears to be arbitrary. It is the understanding of the NAESB subcommittee that R3 only addresses queries submitted under R2.

C. Measures

M1. The Transmission Service Provider shall have documentation that information required by MOD-003-1 R1 was posted on OASIS.

M2. The Transmission Service Provider shall provide upon request the internet location of the OASIS website containing the information required by MOD-003-1 R2.

M3. The Transmission Service Provider shall have documentation, such as a log, containing the information required by MOD-003-1 R3 demonstrating the timeframe within which the answer was provided.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: NERC.

1.2. Compliance Monitoring Period and Reset Timeframe

Rolling 3 years

1.3. Data Retention

Rolling 3 years.

1.4. Additional Compliance Information

None.

2. Mitigation Time Horizon

2.1. Long-term planning – t.b.d.

2.2. Operations Planning - t.b.d.

2.3. Same-day Operation – t.b.d.

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2.4. Real-time Operations – t.b.d.

2.5. Operations Assessment – t.b.d.

3. Violation Severity Level

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3.1. Lower:

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1.3.1. R3: 1 to 5% of the inquiries received were not answered within 1 week during the prior twelve (12) months

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3.2. Moderate:

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2.3.1. R3: more than 5% and up to and including 15% of the inquiries received were not answered within 1 week during the prior twelve (12) months

3.3. High:

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3.3.1. R3: more than 15% and up to and including 30% of the inquiries received were not answered within 1 week during the prior twelve (12) months

3.3.2. R1: Contact information is incorrect

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3.4. Severe:

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4.3.1. R1: Contact information is not posted

4.3.2. R2: Inquiry form is not posted

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4.3.3. R3: more than 5% of the inquiries were never responded to.

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4.3.4. R3: more than 30% of the inquiries received were not answered within 1 week during the prior twelve (12) months

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Comment: Suggestion that a threshold needs to be established for those entities that have low numbers of inquiries.

Comment: There is no real definition what constitutes a valid query. There is potential for queue flooding with spurious queries.

Lohrman's Comment: Queries are for valid questions when denied: why ATC was what it was; rewrite language so that it says what the intent is: for queries to justify denial

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	Dec 13, 2006	T.B.D	Revised

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Deleted: Procedure for Input on

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1	January 22,2007	T.B.D., applicability	Revised

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Procedure for Input on

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TTC and

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Regional

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Procedure for Input on Total Transfer Capability and Available Transfer Capability Methodologies and Values

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the consistent and uniform application

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Transfer Capability

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among Transmission Service Providers, the Regional Reliability Organizations need to review adherence to Regional methodologies

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Total Transfer Capability (TTC) and

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Each Regional Reliability Organization, in conjunction with its members, shall develop and document a procedure on how transmission users can input their concerns or questions regarding the TTC and ATC methodology and values of the Transmission Service Provider(s), and how these concerns or questions will be addressed. The Regional Reliability Organization's procedure shall specify the following:

The name, telephone number and email address of a contact person to whom concerns are to be addressed.

The amount of time it will take for a response

.

The manner in which the response will be communicated (e.g., email, letter, telephone, etc).

What recourse a customer has if the response is deemed unsatisfactory.

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Regional Reliability Organization

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a web site that is accessible by the Regional Reliability Organizations, NERC, and transmission users,

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its procedure for receiving and addressing concerns about

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the TTC and ATC methodology and TTC and ATC values of member Transmission Service Providers

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Attachment 3b

Standard MOD-003-1 — Procedure to resolve comments and questions regarding ATC and AFC Methodologies and Values

NERC drafting team agrees with NAESB and will recommend that this standard be retired when replaced with requirements in a NAESB business practice

A. Introduction

1. **Title:** Procedure to resolve comments and questions regarding ATC and AFC Methodologies and Values

2. **Number:** MOD-003-1

3. **Purpose:** To promote the communication of Transmission Service Provider calculation methodologies and values used for calculating Available Transfer Capability (ATC), and Available Flowgate Capability (AFC) among Transmission Customers.

NAESB Comment: This should be business practice; it only addresses and penalizes failures to communicate. Communication is typically a NAESB business practice development area. Failure to communicate to does not affect reliability of the system.

NAESB Comment: Is this talking about values that go into the calculation or the actual calculated ATC/AFC value itself? Need clarification on this item.

4. **Applicability:**

   4.1. Each Transmission Service Provider

   4.1.1 Entity Limitations. Transmission Service Providers that are not required to have an OASIS may publish on a publicly available Web site the information discussed in the requirements and measurements sections of this standard.

NAESB Comment: Are there any non-jurisdictional entities that 4.1.1 would actually apply to?

5. **Effective Date:** t.b.d.

B. Requirements

R1. The Transmission Service Provider shall post on OASIS the telephone number and email address of a contact person to whom concerns are to be addressed regarding the AFC and the ATC methodologies and their associated numeric values. [Risk factor: t.b.d]

NAESB Comment: Concerned about having two methods of contacting TSPs

NAESB Comment: Being expected to post new names with shift changes will be administrative burden for TP.

NAESB Comment: The person who knows the methodology is not necessarily the same individual who contributes to the day to day ATC/AFC posting; posting of one e-mail address will not necessarily be sufficient for answering all questions.

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NAESB thinks that th a NAESB business pr

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R2. Each Transmission Service Provider shall create on its OASIS an electronic data input ~~field~~ form for the specific purpose of receiving and responding to queries regarding the AFC and the ATC methodologies and their associated numeric values. [Risk factor: t.b.d]

NAESB comment: Need clarification whether standard would allow submission of question through e-mail as provided in R1 or only through OASIS posting as set forth in R2?

NAESB Comment: If questions are accepted through e-mail are those also required to be posted on OASIS?

R3. Subject to commercial confidentiality constraints, within one week of the electronic receipt of a query received via the aforementioned ~~field~~ form in R2, the Transmission Service Provider shall post on OASIS an answer to the received query. [Risk factor: t.b.d]

NERC comment: NAESB will be asked to create a template(s) for OASIS postings

NAESB Comment: If NAESB develops template for posting and is not referenced in the NERC standard, does that mean this requirement lends itself to being adopted by NAESB?

NAESB Comment: R3 treats all queries equally. All queries must be responded to within a week. Some may take longer to respond to due to the nature of the query. Limitation of 1 week appears to be arbitrary. It is the understanding of the NAESB ~~subcommittee that R3 only addresses queries submitted under R2.~~

C. Measures

M1. The Transmission Service Provider shall have documentation that information required by MOD-003-1 R1 was posted on OASIS.

M2. The Transmission Service Provider shall provide upon request the internet location of the OASIS website containing the information required by MOD-003-1 R2.

M3. The Transmission Service Provider shall have documentation, such as a log, containing the information required by MOD-003-1 R3 demonstrating the timeframe within which the answer was provided.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

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Compliance Monitor: NERC.

1.2. Compliance Monitoring Period and Reset Timeframe

Rolling 3 years

1.3. Data Retention

Rolling 3 years

1.4. Additional Compliance Information

None.

2. Mitigation Time Horizon

2.1. Long-term planning – t.b.d.

2.2. Operations Planning - t.b.d.

2.3. Same-day Operation – t.b.d.

2.4. Real-time Operations – t.b.d.

2.5. Operations Assessment – t.b.d.

3. Violation Severity Level

3.1. Lower:

1.3.1. R3: 1 to 5% of the inquiries received were not answered within 1 week during the prior twelve (12) months

3.2. Moderate:

2.3.1. R3: more than 5% and up to and including 15% of the inquiries received were not answered within 1 week during the prior twelve (12) months

3.3. High:

3.3.1. R3: more than 15% and up to and including 30% of the inquiries received were not answered within 1 week during the prior twelve (12) months

3.3.2. R1: Contact information is incorrect

3.4. Severe:

4.3.1. R1: Contact information is not posted

4.3.2. R2: Inquiry form is not posted

4.3.3. R3: more than 5% of the inquiries were never responded to.

4.3.4. R3: more than 30% of the inquiries received were not answered within 1 week during the prior twelve (12) months

NAESB Comment: There is no real definition what constitutes a valid query. There is potential for queue flooding with spurious queries.

NAESB Comment: Suggestion that a threshold needs to be established for those entities that have low numbers of inquiries.

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NERC Comment: Queries are for valid questions when denied: why ATC was what it was; rewrite language so that it says what the intent is: for queries to justify denial

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Comment: There is no real definition what constitutes a valid query. There is potential for queue flooding with spurious queries.¶
Lohrman's Comment: Queries are for valid questions when denied: why ATC was what it was; rewrite language so that it says what the intent is: for queries to justify denial¶
¶

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	Dec 13, 2006	T.B.D	Revised
1	Jan 22, 2007	T.B.D., applicability	Revised
1	Jan 30, 2007	Review with NAESB	Revised with comments

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Procedure for Input on Total Transfer Capability and Available Transfer Capability Methodologies and Values

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the consistent and uniform application

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Transfer Capability

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among Transmission Service Providers, the Regional Reliability Organizations need to review adherence to Regional methodologies

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Total Transfer Capability (TTC) and

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Comment: are there non-jurisdictional entities that 4.1.1 would apply to?

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Each Regional Reliability Organization, in conjunction with its members, shall develop and document a procedure on how transmission users can input their concerns or questions regarding the TTC and ATC methodology and values of the Transmission Service Provider(s), and how these concerns or questions will be addressed. The Regional Reliability Organization's procedure shall specify the following:

The name, telephone number and email address of a contact person to whom concerns are to be addressed.

The amount of time it will take for a response

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The manner in which the response will be communicated (e.g., email, letter, telephone, etc).

What recourse a customer has if the response is deemed unsatisfactory.

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a web site that is accessible by the Regional Reliability Organizations, NERC, and transmission users,

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its procedure for receiving and addressing concerns about

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the TTC and ATC methodology and TTC and ATC values of member Transmission Service Providers

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Comment: The person who knows the methodology is not necessarily the same individual who contributes to the day to day ATC/AFC posting; posting of one e-mail address will not necessarily be sufficient for answering all questions.

Comment: if expected to post new names with shift changes will be administrative burden for TP.

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Comment: Need clarification whether standard would allow submission of question through e-mail as provided in R1 or only through OASIS posting as set forth in R2?

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Comment: If questions are accepted through e-mail are those also required to be posted on OASIS?

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Comment: If NAESB develops template for posting and is not referenced in the NERC standard, does that mean this requirement lends itself to being adopted by NAESB?

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Comment: R3 treats all queries equally. All queries must be responded to within a week. Some may take longer to respond to due to the nature of the query. Limitation of 1 week appears to be arbitrary. It is the understanding of the NAESB subcommittee that R3 only addresses queries submitted under R2.

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that its procedure for receiving input for ATC and TTC methodologies and values meets Reliability Standard MOD-003-0_R1.

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The Regional Reliability Organization shall have evidence that its procedure for receiving input for ATC and TTC methodologies and values is available on a web site accessible by the Regional Reliability Organizations, NERC, and transmission users.

Attachment 4a1

A. Introduction

1 **Title:** Transmission Reliability Margin Calculation Methodology

2 **Number:** MOD-008-1

3 **Purpose:** To promote consistent and transparent Transmission Reliability Margin calculation methodologies among Transmission Service Providers, Transmission Planners, and Transmission Operations Planners.

The drafting team recommends that Transmission Operations Planners should be defined as a new functional model entity for planning periods less than 13 months.

4. **Applicability:**

4.1. Each Transmission Planner

4.2. Each Transmission Operations Planner

4.3. Each Transmission Service Provider

5 **Effective Date:** xxxxxx

B. Requirements

R1. Transmission Service Providers shall use Transmission Reliability Margin ("TRM") in the calculation of ATCs or AFCs if their respective Transmission Planners and Transmission Operations Planners have reserved capacity on their transmission system for use as TRM.

R1.1 Transmission Planners and Transmission Operations Planners may reserve zero (0) TRM. However, Transmission Planners and Transmission Operations Planners that reserve zero (0) TRM must document as to why no TRM is needed.

R2. Transmission Planners and Transmission Operations Planners that reserve TRM must document their methodology for calculating TRM on each posted Contract Path or Flowgate using one or more of the following components:

R2.1. Aggregate Load forecast error (not included in determining generation reliability requirements). Transmission Planners and Transmission Operations Planners must quantify the aggregate load forecast error used and describe how the aggregate load forecast error is used to calculate a TRM value.

R2.2. Load distribution error. Transmission Planners and Transmission Operations Planners must quantify the load distribution error used and describe how the load distribution error is used to calculate a TRM value.

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R2.4 Forecast uncertainty in transmission system topology. Transmission Planners and Transmission Operations Planners must quantify to what degree forecast uncertainty in transmission system topology is used and describe how this quantity is used to calculate a TRM value.

R2.5 Allowances for parallel path (loop flow) impacts. Transmission Planners and Transmission Operations Planners must quantify the allowances for parallel path (loop flow) impacts and describe how this quantity is used to calculate a TRM value.

R2.6 Allowances for simultaneous path interactions. Transmission Planners and Transmission Operations Planners must quantify the allowances for simultaneous path interactions and describe how this quantity is used to calculate a TRM value.

R2.7 Variations in generation dispatch. Transmission Planners and Transmission Operations Planners must quantify variations in generation dispatch and describe how this quantity is used to calculate a TRM value.

R2.8 Short-term System Operator response (Operating Reserve actions not exceeding a 59-minute window). Transmission Planners and Transmission Operations Planners must quantify short-term System Operator response and describe how this quantity is used to calculate a TRM value.

R.2.9 Transmission Planners and Transmission Operations Planners must quantify reserve sharing requirements and describe how this quantity is used to calculate a TRM value.

R3. Transmission Planners and Transmission Operations Planners shall document which of the uncertainties contained in R2.1-R2.9 are accounted for and used to calculate TRM on each posted Contract Path or Flowgate.

R4. Transmission Planners shall calculate and document a TRM value for the Long-term Planning Horizon at least once a year.

R5. Transmission Operations Planners shall calculate and document TRM values for the Short-term Planning Horizon at least once a year.

R6. Transmission Service Provider shall post TRM calculation methodology on OASIS (or its successor).

R7. Transmission Service Provider shall post calculated TRM values on OASIS (or its successor).

R8. The Transmission Service Provider shall use the same components and assumptions in calculating TRM as it uses with its published planning criteria. A TRM value is considered consistent with published planning criteria if the same components that comprise TRM are also used 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.

R9. Transmission Service Providers, Transmission Planners, and Transmission Operations Planners shall use the components of uncertainty from R2.1 through R2.9 solely to calculate TRM and

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not the calculation of CBM.

C. Measures

M1. Each Transmission Service Provider, Transmission Planner, and Transmission Operations Planner shall have and provide upon request the methodology (either electronic or hard copy) as defined in Requirements R1, R2, and R3.

M2. Each Transmission Planner shall have and provide upon request the values (either electronic or hard copy) as defined in Requirement R4.

M3. Each Transmission Operations Planner shall have and provide upon request the values (either electronic or hard copy) as defined in Requirement R5.

M4. Each Transmission Service Provider shall have evidence that it has posted its TRM methodology and value(s) on its OASIS (or its successor) as defined in Requirements R6 and R7.

M5. Each Transmission Service Provider shall have evidence that it has used the same components and assumptions in calculating TRM as it uses with its published planning criteria as defined in Requirement R8.

M6. Each Transmission Service Providers, Transmission Planners, and Transmission Operations Planners shall have evidence that the components of uncertainty in R2.1 to R2.8 used in the calculation of TRM are not used in the calculation of CBM, as defined in Requirement R9.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to verify compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

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

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1.3. Data Retention

Each Transmission Service Provider, Transmission Planner, and Transmission Operations Planner shall have current, in-force documents available as evidence of compliance as specified in each of the Measures.

If an entity is found non-compliant the entity shall keep information related to the non-compliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor.

The Compliance Monitor shall keep for 3 years the last periodic audit report and all requested and submitted subsequent compliance records.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance:

2.1. Level 1: Does not post its methodology for TRM on OASIS (or its successor)

2.2. Level 2: Has not provided upon request its methodology and values for TRM.

2.3. Level 3: Does not use the same components and assumptions in calculating TRM as it uses with its published planning criteria
Does not calculate TRM in accordance with the prescribed schedule.

2.4. Level 4: Does not calculate TRM in accordance with the posted methodology.
Does not have a TRM methodology.

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1.1. Compliance Monitoring Responsibility

Compliance Monitor: ERO.

1.2. Compliance Monitoring Period and Reset Timeframe

xxxxxx

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: xxxxx

2.2. Level 2: xxxxxx.

2.3. Level 3: xxxxx.

2.4. Level 4: xxxx

E. Regional Differences

1. None identified.

Version History

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

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R2.3 Variations in facility loadings due to balancing of generation within a Balancing Authority Area. Transmission Planners and Transmission Operators must quantify to what degree variations in facility loadings due to balancing of generation within a Balancing Authority is used and describe how this quantity is used to calculate a TRM value.

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Transmission Operator

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Transmission Operator

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for various time horizons (use these time horizons from ATC/AFC calculations) on each posted Contract Path or Flowgate.

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R3.1. Transmission Planners and Transmission Operators that separately calculate TRM for each of the uncertainties

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included in R2.1 – R2.8 must document why this method was chosen.

R3.1.1 Transmission Service Providers shall use the largest of the TRM value calculated in R3.1 in ATC/AFC calculations.

R3.2. Transmission Planners and Transmission Operators that calculate TRM using two or more uncertainties

included in R2.1 – R2.8 must document why this method was chosen.

R3.2.1 Transmission Service Providers shall use the TRM value calculated in R3.2 in ATC/AFC calculations.

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for years two (2) through ten (10)

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for year one (months one (1) through twelve (12))

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The entity that should be responsible for R5 should be the

Attachment 4a2

Standard MOD-008-0 — Documentation and Content of Each Regional TRM Methodology

A. Introduction

1. **Title:** Calculation and Documentation of Transmission Reliability Margin
2. **Number:** MOD-008-0
3. **Purpose:** To promote the consistent calculation and documentation of each Transmission Service Provider's Transmission Reliability Margin
4. **Applicability:**
   - 4.1. Transmission Service Provider
5. **Effective Date:**

B. Requirements

R1. Transmission Reliability Margin consists of three components, provision for the outage of a critical unit, the uncertainty component and the generation reserve sharing component. The uncertainty component will by definition be zero. Only the generation reserve sharing component may be a non-zero quantity for the TRM calculation.

R1.1.

R1.2. Each Transmission Service Provider will define and document the MW amounts of transfer capability (on interfaces) or facility ratings (of facilities used as limits in ATC calculations) set aside as the generation reserve sharing component of the Transmission Reliability Margin.

R1.3.1. The Transmission Service Provider will include in its documentation, the methodology describing how the amounts are defined and a copy of the study in which the current amounts are calculated.

R1.3.2. If the amount is zero or the Transmission Service Provider does not participate in generation reserve sharing, all that is needed is a statement reflecting this in the documentation.

R1.3. The Transmission Service Provider will, at a minimum, review its Transmission Reliability Margin quarterly and update any required studies or explanations required in its documentation at that time.

R1.4. The Transmission Service Provider will document the amount of Transmission Reliability Margin that will be subtracted from the Total Transfer Capacity (TTC) on each interface. This amount is the values previously defined in R1.2, if the Transmission Service Provider chose to set a part of Transmission Reliability Margin aside as interface transfer capability.

R1.5. The Transmission Service Provider will document the amount of Transmission Reliability Margin that will be made available to the market as Non-Firm Transmission Service.

R1.6. The Transmission Service Provider will make available its most recent version of its Transmission Reliability Margin documentation on their OASIS website.

C. Measures

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Deleted: 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.

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Deleted: Each Transmission Service Provider must define, within the limits of the standard, and document an amount set aside to make up each component of the Transmission Reliability Margin.

Deleted: Each Transmission Service Provider will define a percentage of transmission element facility ratings (of facilities used as limits in ATC calculations) as the uncertainty component of the Transmission Reliability Margin. Each element or groups of elements may have different percentages set aside as long as it is clear in the documentation what percentage is set aside for each element or group of

Deleted: elements

Deleted: The uncertainty component of TRM will be zero unless a non-zero value can be justified through historical evidence or some yet to be defined method based on good utility practice.

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Deleted: <#>If the percentage defined for a specific element or group of elements, used as limits in ATC calculations, is between 0% and 2%, then the Transmission Service Provider must provide an explanation in its documentation why that percentage is used.¶ ... [1]

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Deleted: <#>Describe the formal process for the Regional Reliability Organization to grant any variance ... [3]

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M1. The Transmission Service Provider's most recent version of the Transmission Reliability Margin documentation is available on their OASIS.

M2. The Transmission Service Provider's most recent version of the documentation contains all items in Reliability Standard MOD-008-1_R1.

The following requirements were extracted from MOD-009 – unsure how to integrate them into this standard.

R2.1. Indicate the frequency under which the verification review shall be implemented.

Put in MOD-008

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

Put in MOD-008

R2.3. Require review of the consistency of the Transmission Service Provider's 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.

Put in MOD-008

R2.4. 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. See R1.3

Put in MOD-008

R3. The TSP 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).

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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.

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.

Or

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

E. Regional Differences

1. None identified.

Version History

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

Page 1: [1] Deleted **Chuck Falls** **1/22/2007 4:08:00 PM**

If the percentage defined for a specific element or group of elements, used as limits in ATC calculations, is between 0% and 2%, then the Transmission Service Provider must provide an explanation in its documentation why that percentage is used.

If a percentage defined for a specific transmission element or group of elements is greater than 5% then the Transmission Service Provider must provide in its documentation an explanation of why the higher percentage is need and historical data that reinforces the explanation. The historical data may include, but is not limited to: load forecast error, load distribution error, loop flow impacts, variations in generation dispatch. A study of the transmission system may be substituted for the historical data if large simultaneous path interactions are the reason a larger amount is used.

Page 1: [2] Deleted **Nate Schweighart** **12/15/2006 9:17:00 AM**

Each Regional Reliability Organization, in conjunction with its members, shall develop and document a Regional TRM methodology. The 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.

Specify the update frequency of TRM calculations.

Specify how TRM values are incorporated into Available Transfer Capability calculations.

Specify the uncertainties accounted for in TRM and the methods used to determine their impacts on the TRM values. 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.

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

Load distribution error.

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

Forecast uncertainty in transmission system topology.

Allowances for parallel path (loop flow) impacts.

Allowances for simultaneous path interactions.

Variations in generation dispatch.

Short-term System Operator response (Operating Reserve actions not exceeding a 59-minute window).

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

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Describe the formal process for the Regional Reliability Organization to grant any variances to individual Transmission Service Providers from the Regional TRM methodology.

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

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

Attachment 7iia

Standard MOD-001-1 — TTC and TFC items removed for transfer to FAC 12/13

Please note that the bullet numbering will no longer match the numbering in MOD-001-1

A. Requirements

R1.

R1.1. Rated System Path Methodology – TTC {these details should be a conforming change to FAC 12/13}

R1.1.1. TTC values will be reviewed and made available on a publicly accessible website, at least semi-annually for summer and winter, unless the transmission owner or transmission operator indicates that operating or system contingencies have changed the TTC.

Comment [A1]: Commenters: Should TTC be determined per the requirements of reliability standards FAC-012 and FAC-013. The ATCT drafting recommends that those requirements should be adjusted to more specifically defined for purposes of this standard.

R1.1.2. As a minimum, the following data must be identified and coordinated by XXXX with the Transmission Service Providers' 1st tier neighbors.

Comment [A2]: Commenters - who should be responsible for this coordination?

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

1.1.2.2. **Powerflow model:** The baseline power flow model for calculating TTC will be made available to neighboring TSPs. Updates to the power flow model shall be provided to neighboring TSPs to reflect facility changes.

1.1.2.3. **Path Definitions and Facility Ratings:** The path definitions and facility ratings shall be exchanged with ATC calculators when revised.

R1.1 **Rated System Path Methodology – TTC** The Planning Coordinator shall provide TTC values (as determined in FAC- 012/013) to the Transmission Service Provider, at least semi-annually for summer and winter, unless the Transmission Owner or Transmission Operator indicates that operating or system contingencies or changes in system topology have changed the TTC. [Risk Factor: Medium]

R1.2.

R1.2.1.

R1.2.2.

R1.2.3. As a minimum, the Transmission Service Provider, shall exchange the following with adjacent Transmission Service Providers:

Comment [A3]: Need to coordinate the requirement to share information with customers with the NAESB business practice development

1.2.3.1. Load levels [move to FAC 12/13]

1.2.3.2. Scheduled and unscheduled transmission outages[move to FAC 12/13]

1.2.3.3. Scheduled and unscheduled generation outages [move to FAC 12/13]

1.2.3.4. Existing transmission reservations, including counterflows [move to FAC 12/13]

1.2.3.5.

R1.3. Network Response Methodology – TTC {these details should be a conforming change to FAC 12/13} [Risk Factor: Medium]

R1.3.1. TTC will be determined per the requirements of reliability standards FAC-012 and FAC-013 by evaluating any changes in system conditions and recalculating values when system conditions change. TTC values will be reviewed and made available on a publicly accessible website,

- daily values for current week at least once a day
- daily values for day 8 through the first month at least once per week
- monthly values for months 2 through 13 at least once per month

Comment [A4]: Commenters: Should FAC-012 Applicability be modified to more specifically mention which entity is responsible, rather leaving determination up to the RRO?

R1.3.1 The Planning Coordinator shall provide TTC values (as determined in FAC- 012/013) to the Transmission Service Provider, at least semi-annually for summer and winter, unless the Transmission Owner or Transmission Operator indicates that operating or system contingencies or changes in system topology have changed the TTC. [Risk factor: Medium]

R1.3.2. The Transmission Service Provider shall make available on a OASIS (or its successor) the following data items:

Comment [A5]: Commenters: How should this be specified i.e, OASIS or its successor?

1.3.2.1. the assumptions used for generation dispatch for both external and internal systems for base case dispatch

1.3.2.2. the assumptions used for transactional modeling shall on its OASIS (or its successor).

1.3.2.3. mathematical algorithms, process flow diagrams, data inputs, identification of flowgates, and modeling assumptions used to perform the TTC and ATC calculations, [move to FAC 12/13]

R1.3.3. The Transmission Service Provider shall, as a minimum, must identify and coordinate the following data by the Transmission Service Provider with adjacent Transmission Service Providers.

Comment [A6]: Need to coordinate the requirement to share information with customers with the NAESB business practice development.
Ok to post:
-Transmission Outages
- ETC except for native load service
- Facility Ratings

1.3.3.1. **Transmission Outage Schedules:** Coordinate transmission system elements scheduled to be taken out of service.

1.3.3.2. **Generation Outage Schedules:** Coordinate generation resources scheduled to be taken out of service.

1.3.3.3. **Generation Dispatch Order:** Provide a typical generation dispatch order or the generation participation factors of all units on an affected Balancing Authority basis. The generation dispatch order will be updated as required by changes in the status of the unit; however, a new generation dispatch order need not be provided more often than prior to each peak load season.

1.3.3.4. **Powerflow model:** The baseline power flow model for calculating TTC will be made available to neighboring TSPs. Updates to the power flow model shall be provided to neighboring TSPs to reflect facility changes.

1.3.3.5. **Facility Ratings:** Facility Ratings shall be exchanged with neighboring TSPs when revised.

1.3.3.6. **Load Forecast:** This information shall be provided daily. [Move to FAC 12/13]

R1.4. Network Response Methodology –ATC {Risk Factor: Medium]

R1.4.1.

R1.4.2.

1.4.2.1.

~~**R1.4.3.**~~

R1.4.4.

R1.4.5. As a minimum, the Transmission Service Provider, shall exchange the following with adjacent Transmission Service Providers.

1.4.5.1. Load levels [move to FAC12/13]

1.4.5.2. Scheduled and unscheduled transmission outages [move to FAC12/13]

1.4.5.3. Scheduled and unscheduled generation outages [move to FAC12/13]

1.4.5.4. Existing transmission reservations, including counterflows[move to FAC 12/13]

Comment [A7]: Need to coordinate the requirement to share information with customers with the NAESB business practice development.
Ok to post:
- ETC except for native load service