NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

NERC ATCT Standards Drafting Team Meeting

Salt River Project Operations Building
POB Mesquite Conf Room x60965
6504 E Thomas Rd, Scottsdale, AZ 85281

March 13, 2007: 8:00 – 5:00 pm (Phoenix Time)
Conference call phone number 1(732)694-2061 Conference code is 1165031307 #
Meeting number: 719 705 913 Meeting password: 123456
https://nerc.webex.com

March 14, 2007: 8:00 am – noon (Phoenix Time)
Conference call phone number 1(732)694-2061 Conference code is 1165031407 #
Meeting number: 711 546 184 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 March 1- 2, 2007 meeting.

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) Complete list of clarification questions.

3) MOD-003-1

a) Status Report

4) TRM – L. Middleton

a) Chairman Middleton will lead the drafting team in a review of the comment form from the changes made to MOD-008 from the last drafting team meeting (**Attachment 4a1**) with respect to the requirements of Order 890.
   1. Is a maximum TRM necessary? If so, what is the reliability reason?
   2. How would the max TRM relate to a more sophisticated methodology – would it govern the maximum of the new methodology.

b) Review other uncertainty proposal (**Attachment 4b1**)

c) Review of MISO TRM procedure (**Attachment 4c1**)

5) ETC Requirements – L. Middleton

a) Chairman Middleton will lead the drafting team in developing proposed requirements for Existing Transmission Commitments requirements (**Attachments 5a1 and 5a2**) with respect to the requirements of Order 890.

(1) Straw man bullet items
- (i) For Network Response and Rated System Path -
- (ii) Look at WECC ATC document

(b) Treatment of firm and non-firm – DuShaune and Kiko
- **1.** reservations that go unscheduled should be offered for sale on a non-firm basis Order 890 para 389 – need to set a window

(c) Treatment of ASTFC in east – Larry / Ray / Don

(d) Documentation / transparency issues – Matt/Larry

(e) Pending transmission commitments/Good Faith Requests - Ray

(f) Roll-over rights – Ron/Don

(g) Counterblows – Nate/Don

(h) Network Native Loads – Shannon
- (i) Future load growth

(i) Grandfathered commitments - Existing transmission contracts (Firm Transmission Reservations for Energy Transactions) – Jerry / Shannon / Nick

(j) Interruptible demands/how included in load forecast - Kiko

(k) Ancillary services – Jerry

(l) Reserving transfer capability over multiple paths to secure capacity for a future undefined resource or purchase - Nate

(m) Impact of parallel flow from 3rd party transactions/ both allocated and undesignated – Ray

(n) 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) Data Exchange among which entities, what data, what frequency - Narinder / Larry –
- (ii) some items might be better handled in the FAC 12/13 – will determine later
- (iii) 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.

(iv) 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.

b) Straw man requirements 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 (after operating reserves are used) – DuShaune
(h) Import of ancillary services – Jerry
(i) Generation outages – Kiko Barredo
(j) Uncommitted Generation components to be included – Nate / Kiko
(k) Relationship to Resource Adequacy SAR/Standard – Bill/Ron
(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
  (i) NAESB is looking at how CBM could be used under what circumstances
(n) Review of issues from NERC CBM whitepaper – Chuck Falls looking for unmet requirements
  1. Review of definition
(o) Documentation / transparency issues – Daryn Barker/ Ray Kershaw

(i) Include any aspects that might be handled by NAESB

(p) Cataloging of various uses and interpretations of CBM – drafting team
  (i) How does it related to LOLP for emergency uses
  (ii) How should they be differentiated?
  (iii) How would CBM be used in an explicit reservation?
  (iv) Should CBM that is being utilized be deducted from CBM as it is deducted from ATC – or should the LOLP be recalculated? How do you avoid double counting?

(q) How and if it would be made a requirement? Ray Kershaw
  (i) Re FERC Order 890 para 261
  (ii) Re FERC Order 980 para 262
  (iii) Would it be source to sink or partial path?
  (iv) How it might impact systems that use CBM for resource adequacy?

(r) Whether there should be a reciprocal agreement for the use of CBM. – drafting team will work with NAESB - should it be acknowledged that the entity on the other side of a CBM flowgate will make the transfer capability available.

(s) Should CBM be based on required or recommended planning reserve? – this is reliability portion – Allan Silk and Ray Kershaw

(t) Whether entities should plan their systems for the amount of CBM being reserved – should it be included in internal networks How should CBM be made consistent with applicable planning criteria? – - DuShaune

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
  (a) Matt Shull

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)
  (a) Nate / Laura

iv) Allocation of TTC based on ownership - needed from a transparency perspective – Narinder/Nate

v) Relationship between FAC 12/13 and other FAC standards (e.g. FAC 8&9)
  (a) Narinder Saini
  (b) Barbara Rehman

vi) Applicability
  (a) Nick Henery

vii) 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) March 21, 2007 Comments distributed to ATCT drafting team
c) March 23, 2007, 11am – 5pm to review comments NERC Webex
d) April 24, 2007 10:00 am – 5:00pm and April 25, 2007 9:00 am – 5:00 pm Joint NERC / NAESB meeting (Central Time) Houston
   (1) *Possible April 23rd or April 26th, NAESB has confirmed availability of April 23rd.*
e) May 15-16 Atlanta (Georgia Transmission Corporation)
f) June 12 – 13 Vancouver / San Francisco
g) July xx xx Chicago/St. Louis
h) August xx Washington/Baltimore
i) September Denver/Salt Lake City

j) Other Webex calls as needed in between face-to-face meetings

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
	Matthew T. Ansley Sr. Engineer	Southern Company Services, Inc. 20 Eddings Lane Montevallo, Alabama 35115	(205) 257-3472 mansley@ southernco.com
	Kiko Barredo	Florida Power & Light Co. 4200 W. Flagler Street Miami, Florida 33134	(305) 442-5073 (305) 442-5790 Fx a_l_barredo@ fpl.com
	Charles Falls	Salt River Project Mail Station POB 100 P.O. Box 52025 Phoenix, Arizona 85072-2025	(602) 236-0965 (602) 236-3896 Fx czfalls@ srpnet.com
	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 4a1

QUESTIONS FOR INDUSTRY COMMENT
FOR
TRM MOD-008

1. Do you agree with the applicable entities defined in the standard?

2. Do you agree that the components included in R.2 are the only components that should be allowed to be considered in TRM? If no, please explain.

3. Is the difference between "aggregate load forecast error" (R2.1) and "Load distribution error" (R2.2) clear? If no, does this require more explanation including perhaps an example?

4. Is the difference between "Parallel paths (loop flow) impacts" (R2.5) and "Simultaneous path interactions" (R2.6) clear ? If no, does this require more explanation including perhaps an example?

5. Is there a chance for double counting when Operating Reserves are allowed for TRM (R2.9) and also for CBM? If yes, what is your recommendation for eliminating this potential?

6. Does requirement R9 eliminate the possibility of counting operating reserves in both the TRM and the CBM calculation (i.e. double counting the same reserves)?

Question 5 and 6 seem to be asking opposing questions, can they be merged into one question?

7. Should this standard be modified to allow for a TRM calculation methodology that specifies an across the board percentage reduction of facility ratings such as suggested in Paragraph 275 of Order 890?

8. Should the standard establish a cap or maximum allowable value for TRM as suggested by Paragraph 275 of Order 890? If yes, please describe the reliability need for such a cap?

9. Should the standard require entities to document the impact of time horizon on the components in the TRM?

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Deleted: to account for the fact that uncertainties associated with the operation of the interconnected electric system increase as the time horizon increases? Therefore the amount of TRM required is time dependant, generally with a larger amount necessary for longer time horizons than for near term time periods? (taken from the NERC white paper on CBM & TRM)

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Attachment 4b1 - Proposed New Uncertainty for MOD-008cm.txt

Proposed New Uncertainty for MOD-008From: Mendrala, Cheryl [cmendrala@iso-ne.com]
Sent: Thursday, March 08, 2007 12:20 PM
To: atctdt@nerc.com
Subject: Proposed New Uncertainty for MOD-008
This email was sent to the atctdt List Serve

All,
I would like to suggest an additional component for TRM associated with the situation I described over the phone at the last meeting. I am including a description of the situation to demonstrate that, while it may be a situation specific to our area, it does impact reliability and it seems to fall under the general 'uncertainties' that TRM is intended for.

Description of situation:
There is a DC facility between HQT and ISNE that has a capability of 2000 MW and under normal system conditions, ISNE can support an import of this amount. This is one of the few facilities in the New England area where true physical reservations are still utilized and the posted TTC is typically 2000 MW. However, since the loss of this facility may expose NY and PJM systems to a contingency more severe than their internal source loss contingencies, NYISO and PJM have the right to restrict the amount of flow ISNE can import in realtime to as low as 1200 MW. The following link describes the interaction between NE, NY and PJM to handle this situation: http://www.iso-ne.com/trans/ops/limits/pjm_ny_ne_proc_method_te_ne_hvdc.doc. Some might propose that this is comparable to a TLR, but Appendix 2 of this document clearly describes why the TLR processes cannot be used to resolve the issue.

Since the realtime operational flow can be limited to 1200 MW, the owners of the facility limit the firm transmission service to 1200 MW by using TRM to affect the desired Firm ATC. This use of TRM does not fall under any of the currently defined uncertainties in the standard. In the 'old world' there was a catch all phrase in the standard that could account for this 800 MW TRM but we have eliminated that catch all phrase in order to promote consistency.

After much wordsmithing, I have narrowed it down to the suggestion below. However, since ISNE performs nearly all functional entitiy responsibilities, I have a hard time understanding how the use of the functional model entities will apply to other regions that are more dispersed. If you have any suggestions for modifying this or an alternate suggestion - I'm all ears.

Suggested New TRM Uncertainty:
Uncertainty Due to External Reliability Coordinator. Transmission Planners and Transmission Operations Planners must quantify how an external Reliability Coordinator can restrict the real-time operation of an element (?below its Normal Rating?) for which the Transmission Planners and Transmission Operations Planners are responsible and describe how this is used to calculate a TRM value.

Thank you,

Cheryl Mendrala
Principal Engineer
ISO New England
413-535-4184

Attachment 5a1

ATC / Existing Transmission Commitment
Suggested Requirements

- The Load Service Entity shall request and the Transmission Service Provider shall reserve on OASIS or its successor, transmission capacity designated to serve the Load Serving Entity's Native Load.

- The Load Service Entity shall request and the Transmission Service Provider shall reserve on OASIS or its successor, transmission capacity designated to serve the Load Serving Entity's Contingency Reserves.

- The Load Serving Entity shall make available on OASIS or its successor its load forecast model and associated assumptions used to determine Native Load and Native Load "G"rowth.

- The Transmission Service Provider shall grant requests for Native Load capacity before all other requests for transmission capacity.

- Transmission capacity designated by the Load Serving Entity for Native Load service after 365 days from the date of request shall be posted by the Transmission Service Provider on OASIS or its successor:
  - As non-firm.
  - In full megawatt quantities of zero and greater.
  - (Definition for native Load "G"rowth?)

- Transmission capacity designated by the Load Serving Entity for Native Load service up to 365 days from the date of request shall be posted by the Transmission Service Provider on OASIS or its successor:
  - As firm.
  - In full megawatt quantities of zero and greater.

- The Transmission Service Provider shall post as non-firm, all transmission capacity that is reserved but unscheduled.

- ETC shall not be used to set aside transfer capability for any type of planning or Contingency Reserve otherwise addressed in CBM or TRM.

- The Load Serving Entity shall be allowed to request from and the Transmission Service Provider shall reserve upon request, transmission capacity granted in the Load Serving Entities executed transmission capacity contracts.

- The Load Serving Entity shall make available upon request, proof of existing transmission contracts upon which it requests transmission capacity.

- The Load Serving Entity shall not publish, release or exchange data on any existing transmission contract where doing so would violate confidentiality constraints contained therein or any other rule or regulation then in force.

- (Concept only / rework wording) The Transmission Service Provider shall post:
  - Scheduled contract-based capacity as firm.
  - Unscheduled contract based capacity as non-firm.
  - Goes to:
    - "In addition, in the short-term ATC calculation, all reserved but unused transfer capability (non-scheduled) shall be released as non-firm ATC." P. 244.

- The Transmission Service Provider shall not decrement transmission capacity for posting on OASIS or its successor until that capacity is scheduled (?Do we wish to add: "or until committed via a good faith request for service."?)

Attachment 5a2

Existing Transmission Commitments (ETC) – Data Exchange Language Item (n)

Each Load Serving Entity and Transmission Service Provider shall exchange the following data related to ETC calculations as agreed upon with the Transmission Service Providers with whom ATC/AFC calculations are coordinated:

1. Load Forecast
2. ……
3. ….
4. …

Items of data to be exchanged will depend on those included in the ETC calculations

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

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.

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

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:

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.

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.

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

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

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