NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL
Princeton Forrestal Village, 116-390 Village Boulevard, Princeton, New Jersey 08540-5731

NERC ATC/TTC/AFC–CBM/TRM Drafting Team

April 6, 2006 — 8 a.m.–1 p.m.
Hyatt Regency Houston
1200 Louisiana
Houston, TX 33607
(713) 654-1234

Meeting Agenda

1. Administration

a. Welcome and Introductions — Bill Blevins
   i) NERC ATC/TTC/AFC– CBM/TRM Roster (**Attachment 1a**)

b. Antitrust Compliance Guidelines (**Attachment 1b**) — Bill Blevins

c. Review of Agenda — Bill Blevins

2. ATC/TTC/AFC Standard

a. SAR — Revision to Existing Standard MOD-001-0 (**Attachment 2**)

b. MOD-001-0 changes

3. CBM/TRM

a. SAR — Revision to Standards MOD-004, MOD-005, MOD-006, MOD-008, and MOD-009 (**Attachment 3a**)

b. MOD-004-0 changes (**Attachment 3b**)

c. MOD-005-0 changes (**Attachment 3c**)

d. MOD-006-0 changes (**Attachment 3d**)

e. MOD-008-0 changes (**Attachment 3e**)

f. MOD-009-0 changes (**Attachment 3f**)

4. Posting

a. Process

b. Initial comment form assignment

c. Responses

5. Next meeting

6. Adjourn

Attachment 1a April 3, 2006

ATC/TTC/AFC and CBM/TRM Revisions Standard Drafting Team Roster

Name	Company
Matthew T. Ansley	Southern Co. Services
Kiko Barredo	Florida Power and Light
Charles Falls	Salt River Project
Mathieu Guillebaud	Southern Company Transmission
E. Nick Henery	SMUD
Raymond K Kershaw	ITC Transmission
Dennis Kimm	MidAmerican Energy
Ross Kovacs	Georgia Transmission Corporation
Laura Lee	Duke Energy
Cheryl Mendrala	ISO New England
Larry Middleton	Midwest ISO
Robert J. Morasco	PJM
Narinder K. Saini	Entergy Services, Inc.
Matthew E. Schull	NC Muni Power Agency #1
Jerry Smith	Arizona Public Service

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NERC ANTITRUST COMPLIANCE GUIDELINES

I. GENERAL

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

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

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

II. PROHIBITED ACTIVITIES

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

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

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.

When completed, e-mail to: mark.ladrow@nerc.net

Standard Authorization Request Form

Title of Proposed Standard	Revision to Existing Standard MOD-001-0
Request Date	Revised February 15, 2006

SAR Requestor Information		**SAR Type** (Put an 'x' in front of one of these selections)	
Name	ATCT SAR Drafting Team atct_plus@nerc.com	☐	New Standard
Primary Contact	Larry Middleton SAR Drafting Team Chair	x	Revision to existing Standard
Telephone Fax	(317) 249-5447	☐	Withdrawal of existing Standard
E-mail	lmiddleton@midwestiso.org	☐	Urgent Action

Purpose/Industry Need (Provide one or two sentences)

This request changes existing modeling standard(s) by adding a requirement for transmission providers to coordinate the calculation of TTC/ATC/AFC and requires that specific reliability practices be incorporated into the TTC/ATC/AFC calculation and coordination methodologies.

Such changes will enhance the reliable use of the transmission system without needlessly limiting commercial activity. This request adds a requirement for documentation of the methodologies used to coordinate TTC/ATC/AFC*. In addition, a requirement is added for the enhanced documentation of the calculation methodology.

The Standards Authorization Request (SAR) drafting team did not address the measures, compliance, and regional differences. Those will be reserved for the standard drafting team.

*TTC – Total Transfer Capability

*ATC – Available Transfer Capability

*AFC – Available Flowgate Capability

*the drafting team may also deem it appropriate to define TFC – Total Flowgate Capability

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies by double clicking the grey boxes.)*		
☐x	Reliability Authority	Ensures the reliability of the bulk transmission system within its Reliability Authority area. This is the highest reliability authority.
☐x	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within its metered boundary and supports system frequency in real time
☐x	Interchange Authority	Authorizes valid and balanced Interchange Schedules
☐x	Planning Authority	Plans the bulk electric system
☐x	Resource Planner	Develops a long-term (>1year) plan for the resource adequacy of specific loads within a Planning Authority area.
☐x	Transmission Planner	Develops a long-term (>1 year) plan for the reliability of transmission systems within its portion of the Planning Authority area.
☐x	Transmission Service Provider	Provides transmission services to qualified market participants under applicable transmission service agreements
☐x	Transmission Owner	Owns transmission facilities
☐x	Transmission Operator	Operates and maintains the transmission facilities, and executes switching orders
☐	Distribution Provider	Provides and operates the “wires” between the transmission system and the customer
☐x	Generator Owner	Owns and maintains generation unit(s)
☐x	Generator Operator	Operates generation unit(s) and performs the functions of supplying energy and Interconnected Operations Services
☐x	Purchasing-Selling Entity	The function of purchasing or selling energy, capacity and all necessary Interconnected Operations Services as required
☐x	Market Operator	Integrates energy, capacity, balancing, and transmission resources to achieve an economic, reliability-constrained dispatch.
☐x	Load-Serving Entity	Secures energy and transmission (and related generation services) to serve the end user

Reliability and Market Interface Principles

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

Does the proposed Standard comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box by double clicking the grey area.)*
1. The planning and operation of bulk electric systems shall recognize that reliability is an essential requirement of a robust North American economy. Yes
2. An Organization Standard shall not give any market participant an unfair competitive advantage.Yes
3. An Organization Standard shall neither mandate nor prohibit any specific market structure. Yes
4. An Organization Standard shall not preclude market solutions to achieving compliance with that Standard. Yes
5. An Organization Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Detailed Description (Provide enough detail so that an independent entity familiar with the industry could draft, modify, or withdraw a Standard based on this description.)

Definitions of Terms used in standard:

The standard drafting team should develop a definition for AFC (and TFC, if needed), and if necessary, revise the definitions for ATC and TTC. (some straw man definitions are contained in Appendix 2)

In those definitions, the standard drafting team should provide clarification (and differentiation) between the uses and application of the defined terms, particularly as the terms would be applied to either specific facilities or paths between two areas.

The standard drafting team should specify how criteria for determining flowgates would be used in an AFC/ATC process.

The standard drafting team should add a requirement for transmission providers to coordinate the calculation of TTC/ATC/AFC and require that specific reliability practices be incorporated into the TTC/ATC/AFC calculation and coordination methodologies.

The standard drafting team should add a requirement for the enhanced documentation of the TTC/ATC/AFC calculation methodology.

NOTE: Many of the specific recommendations for changes to the standard(s) from the SAR drafting team have be moved to Appendix 1 so as to not bind the hands of the standard drafting team.

Below is a list of issues/items that should be addressed in the revision to MOD-001.

The SAR drafting team does not believe any of the existing requirements should be eliminated during this revision; however, the SAR DT expects some existing requirements may be modified and/or re-organized during the revision.

The revisions to this standard should:

- Finalize definitions for TTC (possibly add a definition for TFC), ATC and AFC
- Address the issue of methodology documentation and review of the methodology where an ISO/RTO may span multiple NERC regions
- Include a requirement that will enhance the required documentation of TTC and ATC calculations, increasing transparency of those calculations to the marketplace; also ensure it clearly defines who is responsible for that documentation.
- Require that the methodology document(s) are available to the industry
- Include a list of required data that must be coordinated for TTC and/or ATC/AFC calculations; such as, but not limited to: generation dispatch, transmission and generation outage, load forecasts, flowgate definitions/criteria.
- Consider trying to develop common criteria for establishing flowgates.
- Include a requirement that addresses issues surrounding the need to assign responsibility for analysis of third-party flowgates in TTC/ATC/AFC calculations to avoid double and triple evaluating of the same reservation request.

- Consider adding requirements to address that parties need to ensure 'agreement' between the coordinated ATC/AFCs values and require documentation of a process to define how discrepancies will be handled. For example, TSP1 should be denying service for a path that impacts a flowgate in TSP2 if the data received from TSP2 shows no service is available.
- Ensure requirements exist to document consistency between operational and planning TTC/ATC/AFC calculations.
- Consider changing the current approach of referencing TTC/ATC/AFC requirements as one group and separating them into TTC requirement(s) and AFC/ATC requirement(s)
- Consider adding more description on what is considered a 'standard' methodology (at what level of detail does the 'standard methodology' document need to go and can there be variations/options allowed within the methodology document?);
- Ensure that any mention of a standard methodology clearly refers to TTC or ATC or AFC.
- Consider requiring that the regional document describe what data is being coordinated between what TSPs and why that 'set' of TSPs are coordinating such data. Set a guideline/criteria associated with who must coordinate.
- Ensure that all requirements are stated in such a way that they can be quantified and measured
- Provide clarification of how the standard(s) would apply to the Western and Eastern (also ERCOT) Interconnections. (For example, WECC uses “committed uses or existing transmission committments”.
- Establish a consistent set of definitions across the Western, Eastern, and ERCOT Interconnections, considering aspects of each.
- Establish a baseline set of equations for ATC and AFC and any appropriate component, which would include margins such as those specified in MOD 2, MOD 3, MOD 4, MOD 5, MOD 6, MOD 8, and MOD 9, that will incorporate the set of definitions referred to above, allowing for a zero value for a variable that is not used in a specific interconnection. E.g. : ATC = TTC – committed uses – CBM – TRM. (committed uses may be referred to as base flow or existing transmission commitments.)

This SAR lists items that the Long Term AFC/ATC Task Force (LTATF) and the SAR drafting team believe are required to be addressed in the standard revision. However, this list does not prevent the standard drafting team from proposing additional requirements to ensure the objectives of this standard revision are met.

The SAR drafting team has included suggested changes related to these issues as Appendix 1 to this SAR. These are a result of discussions during the SAR drafting and are provided as information that may aide the Standard drafting team during their work.

If during the development of changes to MOD-001, corresponding changes are required to MOD-002 and MOD-003 for consistency the Standard DT should propose such changes to those standards.

A. Introduction

1. **Title: Development and Documentation of Total Transfer Capability and Available Transfer Capability Calculation Methodologies**
2. **Number:** MOD-001-0

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

4. **Applicability:**

   4.1. Transmission Service Providers and Regional Reliability Organizations

   4.2. Others as may be deemed appropriate by the standard drafting team

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

Related Standards

Standard No.	Explanation
MOD-002-0	Review of TTC and ATC Calculations and Results
FAC-005-0	Electrical Facility Ratings for System Modeling
MOD 003-0	Procedure for Input on TTC and ATC Methodologies and Values

Related SARs

SAR ID	Explanation
T.B.D	SAR for TRM and CBM (submitted with this SAR)
R05004	NAESB proposed Business Practice for a single Business Practice Standard to be developed related to: modifying NAESB Business Practice for Open Access Same-time Information Systems (OASIS) WEQ BPS-001-000, WEQSCP-001-000, and WEQDD-001-000 be modified or developing a new business practice standard(s) as required: 1) the processing of transmission service requests, which use TTC/ATC/AFC,in coordination with NERC changes to MOD 001, 2) 1) the processing of transmission service requests, which use CBM/TRM.
FAC-010-1	Determine Facility Ratings, Operating Limits, and Transfer Capabilities

Regional Differences – to be determined by standard drafting team

Region	Explanation
ECAR	
ERCOT	
FRCC	
MRO	

NPCC	
RFC	
SERC	
SPP	
WECC	

Related NERC Operating Policies or Planning Standards

ID	**Explanation**

Appendix 1

B. Requirements

R1. All Transmission Service Providers within a RRO, shall jointly develop and document a TTC, ATC, and/or AFC methodology that is approved by the RRO.

A Transmission Service Provider that crosses multiple RRO boundaries shall get approval for its TTC, ATC, and/or AFC methodology either from each of the respective RROs, or from NERC.

This methodology shall be available to NERC, the Regions, and the stakeholders in the electricity market.

Each TTC and ATC/AFC methodology shall address each of the items listed below:

R1.1 Include a narrative explaining how TTC and ATC/AFC values are determined and used in evaluating transmission service requests. In addition, an explanation for all items listed here must also include any process that produces values that can override the TTC and ATC/AFC values.

R1.2 Account for how the reservations and schedules for Firm (non-recallable) and Non- firm (recallable) Transmission Service, both within and outside the Transmission Service Provider's system, are included. An explanation must be provided on how reservations that exceed the capability of the specified source point are accounted for. (i.e. how does the Transmission Service Provider's calculation account for multiple concurrent requests for transmission service in excess of a generator's capacity or in excess of a Load Serving Entity's load).

R1.3 Account for the ultimate points of power injection (sources) and power extraction (sinks) in TTC and ATC calculations. Source and sink points are further defined in the Source and Sink Points white paper contained in Appendix B of the Final LTATF Report.

R1.4 Describe how incomplete or so-called partial path transmission reservations are addressed. (Incomplete or partial path transmission reservations are those for which all transmission reservations necessary to complete the transmission path from ultimate source to ultimate sink are not identifiable due to differing reservation priorities, durations, or that the reservations have not all been made.)

R1.5 Require that TTC/ATC/AFC values and postings be reviewed at a minimum frequency and updated if changed to assure proper representation of the transmission system. These values will be made available to stakeholders at a similar frequency.

R1.6 Indicate the treatment and level of customer demands, including interruptible demands.

R1.7 Require that the data listed below, and other data needed by transmission providers for the calculation of TTC and ATC/AFC values are shared and used between Transmission Service Providers. Transmission Service Providers requiring data should request the data as needed. In addition, specify how this information is coordinated and used to determine TTC and ATC/AFC values. If some data is not used or coordinated, provide an explanation. The required minimum update frequency[1] for each item is listed below:

R1.7.1 **Generation Outage Schedules**: Minimum 13 month time frame includes all generators (for 20 MW or more) used in the ATC/AFC calculation). <u>The update frequency is daily.</u> The information exchanged shall differentiate between pending and approved outages.

R1.7.2 **Generation dispatch order**: Generic dispatch participation factors on a control area/market basis. The update frequency is as required.

R1.7.3 **Transmission Outage Schedules**: Minimum 13 month time frame, updated <u>daily</u> for all bulk electric system facilities that impact ATC/AFC calculations; updated once an hour for unscheduled outages. The information exchanged shall differentiate between pending and approved outages.

R1.7.4 **Interchange Schedules** : <u>The update frequency is hourly.</u>

R1.7.5 **Transmission Service Requests**: <u>The update frequency is daily. This will include all requests, regardless of status, for all future time points.</u>

R1.7.6 **Load Forecast**: supplied via the SDX (or similar method), includes hourly data or peak with profile for the next 7-day time frame. <u>The update frequency is daily.</u> In addition, daily peak for day 8 to 30 updated at least daily, and monthly for next 12 months updated at least monthly.

R1.7.7 **Flowgate AFC data exchange:** For transmission service providers in the Eastern Interconnection, firm and non-firm AFC values will be exchanged. The minimum update frequency is as follows: Hourly AFC once-per-hour, Daily AFC once-per-day and Monthly AFC once-per-week. [Note to standard drafting team. See Appendix A from LTATF Final Report section 2.1].

R1.7.8 **Flowgate rating**: Seasonal flowgate ratings will also be provided and exchanged. Users of the flowgate should have the same rating in their calculation as the owner of the facility. Updated as required. [The standard drafting team will need to clarify what

[1] The update frequency specified should allow for improvements in technology, communication, etc, that might better represent actual system conditions.

definitions are used. Would this be TFC, thermal or stability?] [The Standard Drafting team will need to define seasonal.]

R1.7.9 **Calculation model**: Updated models will be made available to neighboring/affected calculators. Changes/upgrades to facilities that would change the rating of the facilities that are limiting facilities should be included the models [joint modeling results can be utilized where applicable]

R1.7.10 **Criteria and definitions:** Flowgates and flowgate definitions/criteria should be exchanged with neighboring/affected calculators on a seasonal basis, or more often as required to represent actual system conditions.

R1.8 Describe how the assumptions for and the calculations of TTC and ATC/AFC values change over different time (such as hourly, daily, and monthly) horizons.

R1.9 Describe assumptions used for positive impacts and counterflow of transmission reservations, and /or schedules, including the basis for the assumptions.

R1.10 Describe assumptions used for generation dispatch for both external and internal systems for base case dispatch and transaction modeling, including the basis for the assumptions.

R1.11 Ensure that the TTC/ATC/AFC calculations are consistent with the Transmission Owner's/Transmission Planner's (leave Functional Model designation to Standard DT) planning criteria and operating criteria [The standard drafting team will need to be more specific regarding time frames].
Note: this regards, for example 1) TSR studies not being subjected to more stringent criteria than what is in the planning studies, and 2) negative ATC/AFC are shown over long periods of time on an operating basis, but planning studies show no anticipated remedies.

R1.12 Describe the formal process for the granting of any variances to individual transmission service providers from the TTC/ATC/AFC methodology. (Standard Drafting team will describe who is responsible.)

- Any variances must be approved by NERC or its designate

R2. The most recent version of the documentation of each TTC, ATC, and AFC methodology shall be available on a web site accessible by NERC, the Regions, and the stakeholders in the electricity market. [standard drafting team: NEED to add a description how this would apply in WECC for TTC.]

C. Measures.
(<u>standard drafting team to develop procedures for audit to ensure adherence to stated methodology – see Appendix 3</u>)

Appendix 2

Strawman Definitions from LTATF:

Total Transfer Capability (TTC):

TTC and ATC are defined in standard 1E1
Existing Transmission Commitments (ETC)
ATC is expressed as:
ATC = TTC – Existing Transmission Commitments) – CBM – TRM

Flowgate is the name given to the transmission element(s) and associated contingency(ies) if any, that may limit transfer capability.

Flowgate Criteria – to be determined by SDT

Available Flowgate Capability (AFC)
AFC is expressed as:
AFC = [to be finalized by SDT]

The relationship between ATC and AFC is as follows:

$ATC_{(\text{Path A-B})}=AFC_{(\text{Most Limiting Flowgate for Path A-B})}/\text{Distribution Factor}_{(\text{Path A-B on Limiting Flowgate})}$

Daily, Monthly, Yearly TTC
Daily, Monthly, Yearly ATC
Daily, Monthly, Yearly TRM
Daily, Monthly, Yearly CBM

Appendix 3 LTATF Suggested Audit Methodology

M1. Each group of transmission service providers within a region, in conjunction with the members of that region, shall jointly develop and implement a procedure to review periodically (at least annually) and ensure that the TTC and ATC/AFC calculations and resulting values of member transmission providers comply with the Regional TTC and ATC/AFC methodology, the NERC Planning Standards, and applicable Regional criteria.

M2. A review to verify that the ATC/TTC/AFC calculations are consistent with the TO's/TP's planning criteria is also required. The procedure used to verify the consistency must also be documented in the report. Documentation of the results of the most current reviews shall be provided to NERC within 30 Days of completion.

M3. Each entity responsible for the TTC and ATC/AFC methodology, in conjunction with its members and stakeholders, shall have and document a procedure on how stakeholders can input their concerns or questions regarding the TTC and ATC/AFC methodology and values of the transmission provider(s), and how these concerns or questions will be addressed. Documentation of the procedure shall be available on a web site accessible by the Regions, NERC, and the stakeholders in the electricity market.

M4. The RRO must review and approve the ATC/TTC/AFC methodology to ensure it is consistent with the RRO's Planning and Operating Criteria.

The RRO is responsible for ensuring that TTC and ATC/AFC calculations are consistent with the individual TOs/TPs planning criteria.

Each procedure shall specify:

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

b) The amount of time it will take for a response.

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

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

When completed, e-mail to: gerry.cauley@nerc.net

Standard Authorization Request Form

Title of Proposed Standard	Revision to Standards MOD 004, MOD005, MOD006, MOD 008, and MOD 009
Request Date	revised February 15, 2006

SAR Requestor Information		**SAR Type** (Put an 'x' in front of one of these selections)
Name ATCT SAR Drafting Team atctdt_plus@nerc.com	☐ ☐	New Standard
Primary Contact Larry Middleton SAR Drafting Team Chair	☐ X	Revision to existing Standard(s)
Telephone (317) 249-5447 Fax	☐ ☐	Withdrawal of existing Standard
E-mail lmiddleton@midwestiso.org	☐ ☐	Urgent Action

Purpose/Industry Need (Provide one or two sentences)

The existing standards on TRM should be revised to require crisp and clear documentation of the calculation of TRM and make various components of the methodology mandatory so there is more consistency across methodologies.

The existing standards on CBM should be revised to require crisp and clear documentation of the calculation of CBM and make various components (zero values could be acceptable, if applicable) of the methodology mandatory so there is more consistency across methodologies. The Standard drafting team should identify and clarify the various definitions of CBM.

The SAR drafting team will not be addressing the measures, compliance, and regional differences. Those will be reserved for the Standard Drafting Team. The Standard Drafting Team should also consider whether the definitions of CBM and TRM should be revised.

The Standard Drafting Team should coordinate its work with the related proposal for the draft NAESB business practice R05004.

Detailed Description (Provide enough detail so that an independent entity familiar with the industry could draft, modify, or withdraw a Standard based on this description.)

Below is a list of issues/items that should be addressed in the revision to MOD-004, 5, 6, 8, and 9. The SAR drafting team does not believe any of the existing requirements should be eliminated during this revision; however, the SAR drafting team expects some existing requirements may be modified and/or re-organized during the revision.

In addition to the specific changes suggested in the SAR Appendix 1, the revisions to these standards should address these additional issues:

- Cataloging of various uses and interpretations of CBM
  - How should they be differentiated?
- Should CBM be an explicit reservation?
  - How and if it would be made a requirement
  - Would it be source to sink or partial path?
- How it might impact systems that use CBM for resource adequacy?
- Whether there should be a reciprocal agreement for the use of CBM.
- Should CBM be based on required or recommended planning reserve.
- Whether entities should plan and reinforce their systems for the amount of CBM being reserved.
- How would RRO (and NERC?) approve CBM/TRM methodologies
- How should TRM be made consistent with applicable planning criteria?

The SAR drafting team has included suggested changes related to these issues in Appendix 1 to this SAR. These are a result of discussions during the SAR drafting and are provided as information that may aide the standard drafting team during their work.

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies by double clicking the grey boxes.)*		
☐x	Reliability Authority	Ensures the reliability of the bulk transmission system within its Reliability Authority area. This is the highest reliability authority.
☐x	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within its metered boundary and supports system frequency in real time
☐x	Interchange Authority	Authorizes valid and balanced Interchange Schedules
☐x	Planning Authority	Plans the bulk electric system
☐x	Resource Planner	Develops a long-term (>1year) plan for the resource adequacy of specific loads within a Planning Authority area.
☐x	Transmission Planner	Develops a long-term (>1 year) plan for the reliability of transmission systems within its portion of the Planning Authority area.
☐**x**	Transmission Service Provider	Provides transmission services to qualified market participants under applicable transmission service agreements
☐x	Transmission Owner	Owns transmission facilities
☐x	Transmission Operator	Operates and maintains the transmission facilities, and executes switching orders
☐	Distribution Provider	Provides and operates the "wires" between the transmission system and the customer
☐x	Generator Owner	Owns and maintains generation unit(s)
☐x	Generator Operator	Operates generation unit(s) and performs the functions of supplying energy and Interconnected Operations Services
☐x	Purchasing-Selling Entity	The function of purchasing or selling energy, capacity and all necessary Interconnected Operations Services as required
☐x	Market Operator	Integrates energy, capacity, balancing, and transmission resources to achieve an economic, reliability-constrained dispatch.
☐x	Load-Serving Entity	Secures energy and transmission (and related generation services) to serve the end user

Applicability to be determined by standard drafting team.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check boxes for all that apply by double clicking the grey boxes.)*	
x☐	Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	The frequency and voltage of interconnected bulk electric systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☐x	Information necessary for the planning and operation of interconnected bulk electric systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented.
☐x	Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems.
☐x	Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified and have the responsibility and authority to implement actions.
☐	The security of the interconnected bulk electric systems shall be assessed, monitored and maintained on a wide area basis.

Does the proposed Standard comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box by double clicking the grey area.)*
The planning and operation of bulk electric systems shall recognize that reliability is an essential requirement of a robust North American economy. Yes
An Organization Standard shall not give any market participant an unfair competitive advantage.Yes
An Organization Standard shall neither mandate nor prohibit any specific market structure. Yes
An Organization Standard shall not preclude market solutions to achieving compliance with that Standard. Yes
An Organization Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Related Standards

Standard No.	Explanation
t.b.d	LTATF SAR for ATC/AFC and TTC (submitted with this SAR).
R05004	NAESB proposed Business Practice for a single Business Practice Standard.

Related SARs

SAR ID	Explanation
	Resource Adequacy SAR/Standard

Regional Differences

Region	Explanation
ECAR	
ERCOT	
FRCC	
MRO	
NPCC	
RFC	
SERC	
SPP	
WECC	

Related NERC Operating Policies or Planning Standards

ID	Explanation

Appendix 1

proposed changes are highlighted in green

SUGGESTED REVISIONS to MOD-004-0

R1. Each Regional Reliability Organization, in conjunction with its members, shall develop and document a CBM methodology that is approved by the RRO. A Transmission Service Provider that crosses multiple RRO boundaries shall get approval for its CBM methodology either from each of the respective RROs, or from NERC.

Each CBM methodology shall :

R1.1 Specify that the method used to determine generation reliability requirements as the basis for CBM shall be consistent with the respective generation planning criteria.

R1.2 Specify the frequency of calculation of the generation reliability requirement and associated CBM values.

- Require that the calculations must be verified at least annually.
- Require that the dates seasonal CBM values apply must be specified.

R1.3 Require that generation unit outages considered in a transmission provider's CBM calculation be restricted to those units within the transmission provider's system.

[The standard drafting team should discuss whether CBM should be an explicit reservation and how it would be made a requirement.]

R1.4 Require that CBM be preserved only on the transmission provider's system where the load serving entity's load is located (i.e., CBM is an import quantity only).

[The standard drafting team should discuss whether there could be a reciprocal agreement for the use of CBM.]

R1.5 Describe the inclusion or exclusion rationale in the CBM calculation for generation resources of each LSE including those generation resources not directly connected to the transmission provider's system but serving LSE loads connected to the transmission provider's system. The following rationale must be included in all methodologies:

R1.7.1 All generation directly connected to the transmission provider's system being used to serve load directly connected to that system will be considered in the CBM requirement determination.

R1.7.2 The availability of generation not directly connected to the transmission provider's system being used to serve load directly connected to that system would be considered available per the terms under which it was arranged.

R1.6 Describe the inclusion or exclusion rationale for generation connected to the transmission provider's system. The following rationale must be included in all methodologies:

R1.7.1 The following units shall be included in the CBM requirement determination because they are considered to be the installed generation capacity, committed to serve load, directly connected to the transmission system for which the CBM requirement is being determined:

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

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

2. Generation directly connected to the TSP's system, but not committed to serve load on any system, will be included in the CBM requirement determination for the transmission system to which the generator is directly connected as follows:

The TSP will use the best information available to them (i.e. confirmed or requested transmission service/no service) to determine how these units should be considered in the CBM requirement determination. All assumptions made must be documented and approved by the entity responsible for the methodology.

R1.7 Describe the formal process and rationale for the RRO to grant any variances to individual transmission providers from the Regional CBM methodology.

R1.7.1 Require any variances must also be approved by NERC or its designate.

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

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

R1.10 Describe any adjustments to CBM values to account for generation reserve sharing arrangements (i.e. Use of CBM and a reserve sharing event simultaneously occurring that is not planned for). Explain how the simultaneous application of CBM and TRM amounts being implemented in the ATC calculations are being taken into consideration during the planning process.

[The standard drafting team should consider paragraph below:]

R1.11 Require that CBM be based on the required or recommended planning reserve. In other words, a load serving entity that does not arrange for resources at least equal to the recommended or required planning reserve levels does not benefit by causing a higher CBM.

[The standard drafting team should consider the option below:]

R1.12 Require that the appropriate entities will plan and reinforce the transmission system for the amount of CBM being preserved.

R2. The RRO's most recent version of the documentation of each entity's CBM methodology shall be available on a web site accessible by NERC, the RROs, and the stakeholders in the electricity market.

M3. Each RRO, in conjunction with its members, shall develop and implement a procedure to review the CBM calculations and values of member transmission providers to ensure that they comply with the Regional CBM methodology and are periodically updated (at least annually) and available to stakeholders. Documentation of the results of the most current Regional reviews shall be provided to NERC or its designate within 30 days of completion.

- The RRO must review and approve the TSP methodology to ensure it is consistent with the RRO's Planning Criteria. The TSP is responsible for ensuring that CBM calculations are consistent with the individual TOs planning criteria.

SUGGESTED REVISIONS to MOD-005-0

R1. Each Regional Reliability Organization, in conjunction with its members, shall develop and implement a procedure to review (at least annually) the CBM calculations and the resulting values of member Transmission Service Providers. The CBM review procedure shall:

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

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

R1.3 Require review of the consistency of the transmission provider's CBM components with its published planning criteria. A CBM value is considered consistent with published planning criteria if the same components that comprise CBM are also addressed in the planning criteria. The methodology used to determine and apply CBM does not have to involve the same mechanics as the planning process, but the same uncertainties must be considered and any simplifying assumptions explained. It is recognized that ATC determinations are often time constrained and thus will not permit the use of the same mechanics employed in the more rigorous planning process. The procedure must specify how the consistency would be verified.

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

R1.4 Require CBM values to be updated at least annually and available to the Regions, NERC, and stakeholders in the electricity markets.

R2. The documentation of the Regional CBM procedure shall be available to NERC on request (within 30 days).

R3. Documentation of the results of the most current implementation of the procedure shall be sent to NERC within 30 days of completion.

SUGGESTED **REVISIONS to MOD-008-0**

R1. Each RRO in conjunction with its members, shall jointly develop and document a TRM methodology. This methodology shall be available to NERC, the Regions, and the transmission users in the electricity market. If a RRO's members TRM values are determined by a RTO or ISO, than a jointly developed regional methodology is not required for those members. RRO members not covered by an RTO/ISO would be required to have a regional methodology.

Each TRM methodology shall:

R1.1 Specify the update frequency of TRM calculations.

- Require that calculations be verified at least annually if determined to be required
- Require that dates that seasonal TRM values apply must be specified

R1.2 Specify how TRM values are incorporated into ATC calculations.

R1.3 Specify the uncertainties accounted for in TRM and the methods used to determine their impacts on the TRM values. The following components of uncertainty, if applied, shall be accounted for solely in TRM and not CBM:

R1.3.1 aggregate load forecast error (not included in determining generation reliability requirements).
R1.3.2 load distribution error.
R1.3.3 variations in facility loadings due to balancing of generation within a Balancing Authority Area.
R1.3.4 forecast uncertainty in transmission system topology.
R1.3.5 allowances for parallel path (loop flow) impacts.
R1.3.6 allowances for simultaneous path interactions.
R1.3.7 variations in generation dispatch
R1.3.8 short-term operator response (operating reserve actions not exceeding a 59-minute window).
R1.3.9 Any additional components of uncertainty shall benefit the interconnected transmission systems, as a whole, before they shall be permitted to be included in TRM calculations.
R1.3.10 Additional detail on how variations in generation dispatch are handled from intermittent generation sources such as wind and hydro, need to be provided.

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

R1.5 Describe the formal process for the granting of any variances to individual transmission service providers from the regional TRM methodology.

R1.5.1 Any variances must also be approved by NERC or its designate

R1.6 Describe the methodology and conditions thereof that are used to reflect if TRM is reduced for the operating horizon.

R1.7 Explain how the simultaneous application of CBM and TRM amounts being implemented in the ATC calculations are being taken into consideration during the planning process.

R1.8 Specify TRM methodologies and values must be consistent with the approved planning criteria.

R1.8.1 Require that the appropriate entities will plan and reinforce the transmission system for the amount of TRM being preserved. The methodology must specify how the verification of the consistency would be determined.

R1.8.2 Each TRM methodology shall address each of the items above and shall explain its use, if any, in determining TRM values. Other items that are entity specific or that are considered in each respective methodology shall also be explained along with their use in determining TRM values.

SUGGESTED **REVISIONS to MOD-009-0**

R1. Each group of transmission service providers/and or AFC/ATC/TTC calculators within a region, in conjunction with the members of that region , in conjunction with its members, shall develop and implement a procedure to review the TRM calculations and resulting values of member transmission providers to ensure that they comply with the regional TRM methodology and are updated at least annually and available to transmission users.

- The RRO must review and approve the transmission service provider(s)' methodology to ensure it is consistent with the RRO's Planning Criteria. The RRO is responsible for ensuring that TRM calculations are consistent with the individual TOs planning criteria.

The TRM review procedure shall:

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

R1.2 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 stakeholders.

R1.3 Require review of the consistency of the transmission service provider's or Transmission Owner'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. It is recognized that ATC determinations are often time constrained and thus will not permit the use of the same mechanics employed in the more rigorous planning process. The review process used by a transmission service provider or transmission owner also needs to be documented.

R1.3.1 Explain how the simultaneous application of CBM and TRM amounts being implemented in the ATC calculations are being taken into consideration during the planning process.

R1.4 TRM methodologies and values must be consistent with the applicable planning criteria

- The methodology must specify how the verification of the consistency would be determined

R2. The documentation of the regional TRM procedure shall be available to NERC on request (within 30 days). Documentation of the results of the most current implementation of the procedure shall be available to NERC within 30 days of completion.

R3. Documentation of the results of the most current regional reviews shall be provided to NERC within 30 days of completion.

R4. Require TRM values to be verified at least annually and made available to the RROs, NERC, and stakeholders.

A. Introduction

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

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

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

4. **Applicability:**

   4.1. Regional Reliability Organization

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

B. Requirements

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

R1.1. Specify that the method used by each Regional Reliability Organization member to determine its generation reliability requirements as the basis for CBM shall be consistent with its generation planning criteria.

R1.2. Specify the frequency of calculation of the generation reliability requirement and associated CBM values.

R1.3. Require that generation unit outages considered in a Transmission Service Provider's CBM calculation be restricted to those units within the Transmission Service Provider's system.

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

R1.5. Describe the inclusion or exclusion rationale for generation resources of each Load-Serving Entity including those generation resources not directly connected to the Transmission Service Provider's system but serving Load-Serving Entity loads connected to the Transmission Service Provider's system.

R1.6. Describe the inclusion or exclusion rationale for generation connected to the Transmission Service Provider's system but not obligated to serve Native/Network Load connected to the Transmission Service Provider's system.

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

R1.8. Specify the relationship of CBM to the generation reliability requirement and the allocation of the CBM values to the appropriate transmission facilities. The sum of the

CBM values allocated to all interfaces shall not exceed that portion of the generation reliability requirement that is to be provided by outside resources.

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

R1.10. Describe the inclusion or exclusion rationale for generation reserve sharing arrangements in the CBM values.

R2. The Regional Reliability Organization shall make the most recent version of the documentation of its CBM methodology available on a website accessible by NERC, the Regional Reliability Organizations, and transmission users.

C. Measures

M1. The Regional Reliability Organization's most recent CBM methodology documentation shall meet Reliability Standard MOD-004-0_R1.

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

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: NERC.

1.2. Compliance Monitoring Period and Reset Timeframe

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

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

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

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

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

E. Regional Differences

1. None identified.

Version History

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

A. Introduction

1. **Title:** **Procedure for Verifying Capacity Benefit Margin Values**
2. **Number:** MOD-005-0
3. **Purpose:** To promote the consistent and uniform application of Transfer Capability calculations among transmission system users, the Regional Reliability Organizations need to review adherence to Regional methodologies for calculating Capacity Benefit Margin (CBM).
4. **Applicability:**
   - **4.1.** Regional Reliability Organization
5. **Effective Date:** April 1, 2005

B. Requirements

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

- **R1.1.** Indicate the frequency under which the verification review shall be implemented.
- **R1.2.** Require review of the process by which CBM values are updated, and their frequency of update, to ensure that the most current CBM values are available to transmission users.
- **R1.3.** Require review of the consistency of the Transmission Service Provider's CBM components with its published planning criteria. A CBM value is considered consistent with published planning criteria if the components that comprise CBM are addressed in the planning criteria. The methodology used to determine and apply CBM does not have to involve the same mechanics as the planning process, but the same uncertainties must be considered and any simplifying assumptions explained.
- **R1.4.** Require CBM values to be periodically updated (at least annually) and available to the Regional Reliability Organizations, NERC, and transmission users.

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

R3. The Regional Reliability Organization shall provide documentation of the results of the most current implementation of its CBM review procedure to NERC on request (within 30 calendar days).

C. Measures

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

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

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

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: NERC.

1.2. Compliance Monitoring Period and Reset Timeframe

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

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

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

2.3. Level 3: Not applicable.

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

E. Regional Differences

1. None identified.

Version History

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

A. Introduction

1. **Title:** **Procedures for the Use of Capacity Benefit Margin Values**

2. **Number:** MOD-006-0

3. **Purpose:** To promote the consistent and uniform use of transmission Transfer Capability margins calculations among transmission system users,

4. **Applicability:**

   4.1. Transmission Service Provider

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

B. Requirements

R1. Each Transmission Service Provider shall document its procedure on the use of Capacity Benefit Margin (CBM) (scheduling of energy against a CBM preservation). The procedure shall include the following three components:

R1.1. Require that CBM be used only after the following steps have been taken (as time permits): all non-firm sales have been terminated, Direct-Control Load Management has been implemented, and customer interruptible demands have been interrupted. CBM may be used to reestablish Operating Reserves.

R1.2. Require that CBM shall only be used if the Load-Serving Entity calling for its use is experiencing a generation deficiency and its Transmission Service Provider is also experiencing Transmission Constraints relative to imports of energy on its transmission system.

R1.3. Describe the conditions under which CBM may be available as Non-Firm Transmission Service.

R2. Each Transmission Service Provider shall make its CBM use procedure available on a web site accessible by the Regional Reliability Organizations, NERC, and transmission users..

C. Measures

M1. The Transmission Service Provider's procedure for the use of CBM (scheduling of energy against a CBM preservation) shall meet Reliability Standard MOD-006-0_R1.

M2. The Transmission Service Provider's procedure for the use of CBM (scheduling of energy against a CBM preservation) shall be available on a web site accessible by the Regional Reliability Organizations, NERC, and transmission users.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Compliance Monitor: Regional Reliability Organizations

   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 Transmission Service Provider's procedure for use of CBM is available and addresses only two of the three requirements for such documentation as listed above under Reliability Standard MOD-006-0_R1.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: The Transmission Service Provider's procedure for use of CBM addresses one or none of the three requirements as listed above under Reliability Standard MOD-006-0_R1, or is not available.

E. Regional Differences

1. None identified.

Version History

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

A. Introduction

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

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

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

4. **Applicability:**

   4.1. Regional Reliability Organization

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

B. Requirements

R1. 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.

R1.1. Specify the update frequency of TRM calculations.

R1.2. Specify how TRM values are incorporated into Available Transfer Capability calculations.

R1.3. 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.

R1.3.1. Aggregate Load forecast error (not included in determining generation reliability requirements).

R1.3.2. Load distribution error.

R1.3.3. Variations in facility Loadings due to balancing of generation within a Balancing Authority Area.

R1.3.4. Forecast uncertainty in transmission system topology.

R1.3.5. Allowances for parallel path (loop flow) impacts.

R1.3.6. Allowances for simultaneous path interactions.

R1.3.7. Variations in generation dispatch.

R1.3.8. Short-term System Operator response (Operating Reserve actions not exceeding a 59-minute window).

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

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

R2. 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.

C. Measures

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

M2. The Regional Reliability Organization's most recent version of the documentation of its TRM contains all items in Reliability Standard MOD-008-0_R1.

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

A. Introduction

1. **Title:** **Procedure for Verifying Transmission Reliability Margin Values**
2. **Number:** MOD-009-0
3. **Purpose:** To promote the consistent application of transmission Transfer Capability margin calculations among Transmission System Providers and Transmission Owners.
4. **Applicability:**
   4.1. Regional Reliability Organization
5. **Effective Date:** April 1, 2005

B. Requirements

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

R1.1. Indicate the frequency under which the verification review shall be implemented.

R1.2. 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.

R1.3. 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.

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

R2. The Regional Reliability Organization shall make documentation of its Regional TRM review procedure available to NERC on request (within 30 calendar days).

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

C. Measures

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

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

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: NERC.

1.2. Compliance Monitoring Period and Reset Timeframe

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

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

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

2.3. Level 3: Not applicable.

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

E. Regional Differences

1. None identified.

Version History

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