

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

Notice of Proposed Rulemaking on)	Docket Nos.:
Preventing Undue Discrimination and)	RM05-25-000
Preference in Transmission Service)	RM05-17-000

**COMMENTS OF THE
NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL
ON ATC AND ATC-RELATED ISSUES**

The North American Electric Reliability Council¹, a New Jersey nonprofit corporation (“NERC”), is pleased to provide these comments in response to the issues and questions raised in the Commission’s May 19, 2006 Notice of Proposed Rulemaking (NOPR), “Preventing Undue Discrimination and Preference in Transmission Service.”

NERC supports the Commission’s efforts to ensure transmission services are provided in a nondiscriminatory and just and reasonable basis. NERC further supports the Commission in encouraging the electric industry to work toward increased communication, coordination, consistency, and transparency in the calculation and application of Available Transfer Capability (“ATC”) and related ATC values², while protecting the reliability of the bulk power system.

¹ NERC was formed after the Northeast blackout in 1965 to promote the reliability of the interconnected electric systems in North America. Its mission is to ensure that the bulk electric systems that serve North America are adequate, reliable, and secure. It works with all segments of the electric industry as well as customers to “keep the lights on” by developing and encouraging compliance with rules for the reliable operation and adequacy of supply of these systems. NERC comprises eight regional reliability councils that account for virtually all the electricity supplied in the United States, Canada, and a portion of Baja California Norte, Mexico. Recently, the Commission certified the North American Electric Reliability Corporation, a NERC affiliate, as the Electric Reliability Organization under Section 215 of the Federal Power Act.

² ATC-related values include: Total Transfer Capability (TTC), Transmission Reliability Margin (TRM), Capacity Benefit Margin (CBM), and Available Flowgate Capability (AFC).

NERC will focus its comments, herein, on ATC and ATC-related issues raised in the NOPR.

Background

NERC, in its [August 15, 2005 comments on the Commission's Notice of Inquiry, "Information Requirements for Available Transfer Capability,"](#) agreed that there is a need to continue the enhancement of the calculation of ATC and ATC-related values to support the wholesale power market while maintaining adequate reliability for all users, owners, and operators of the bulk power system. NERC also indicated its support of the recommendations of its Long-Term AFC/ATC Task Force (LTATF), the Commission, and the industry to add increased standardization and consistency to the current NERC reliability standards on ATC and ATC-related values. However, NERC urged caution to ensure that ATC calculations and their application be consistent with other NERC reliability standards, regional reliability criteria, and transmission owners' operating and planning criteria.

Status of NERC ATC Standards Revisions

Since it filed its comments on the Commission's Notice of Inquiry, NERC has undertaken a review and revision of its standards related to ATC calculation and coordination. Currently, NERC has two standards under active development that propose to revise its existing standards on ATC and ATC-related and CBM and TRM-related issues:

["Revision to Existing Standard MOD-001-0," February 15, 2006](#) (Attachment 1)

[“Revision to Standards MOD-004, MOD-005, MOD-006, MOD-008, and MOD-009,” February 15, 2006](#) (Attachment 2)

NERC is addressing ATC and ATC-related and CMB and TRM-related issues from a reliability perspective in its standards revisions noted above. NERC is coordinating its efforts with those of the North American Energy Standards Board (NAESB) on a related proposed business practice standard, R05004, following the NERC NAESB Procedure for Joint Standards Development and Coordination.

The proposed changes to NERC’s existing modeling standards would add 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. The existing standards on TRM and CBM are also proposed to be revised to require crisp and clear documentation of the calculation of TRM and CBM and make various components of the methodology mandatory so there is more consistency across methodologies. Such changes will enhance the reliable use of the transmission system without needlessly limiting commercial activity.

NERC submits that a great deal of progress has been made since the proposed standards were approved for development by the NERC Standards Committee in February 2006 to address the recommendations made by the LTATF. NERC expects its revised standards to be finalized for submission to the Commission prior to the summer

of 2007. NERC and the electric industry are giving high priority to these standards revisions, consistent with the entire spectrum of standards development activities currently under way, especially those standards initiatives that have been undertaken in response to the recommendations from the August 2003 blackout investigation.

Questions on ATC and ATC-Related Values

A number of questions on ATC and ATC-related values have been posed and discussed within the industry and with Commission staff. These questions and NERC's responses to them are listed below.

What, if any concerns, do you have with the current methods and processes used to calculate ATC/CBM/TRM?

- NERC Reliability Standards for ATC, TTC, CBM and TRM were established in 1997 and revised in 2002.
- Problems with the calculated values result from different interpretations of definitions, oversimplification of calculations, lack of sharing data, and assumptions between neighboring ATC calculators, and different calculation frequencies and times.
- Each TSP will consider in its TTC and ATC/AFC determination process all third party flowgates. Transactions that have a response factor equal to or greater than the response factor cut off threshold used by the owning TSP should be used in order to

determine which transactions are significant. At a minimum, flowgates on transmission systems that comprise the first tier need to be coordinated and the modeling needs to be adequate to produce reasonable response factors for those first tier flowgates.

What changes, if any, should the Commission pursue? If changes are recommended, what guiding policy principles should the Commission adopt?

- ATC values are not reliability indicators, but rather derived from reliability-based standards and the physical characteristics and limitations of the electric system.
[ATC = TTC - Existing Transmission Commitments - CBM - TRM]
- The ATC values represent the transmission transfer capability that can be utilized by the market while still maintaining reliability.
- NERC needs to define the parameters for determining TTC, CBM and TRM, while NAESB needs to address the appropriate business practices and communications protocols for requesting and scheduling different types of transmission service using ATC. This process should proceed using the NERC NAESB Procedure for Joint Standards Development and Coordination.
- The LTATF developed two SARs for proposed revisions to NERC reliability standards and a new NAESB business practice to address increased communication,

coordination, and consistency in the calculation of TTC, CBM, TRM, and reservation of ATC.

- ATC Standard — Revise existing reliability standards by adding a requirement for transmission providers to coordinate the calculation of ATC and require that specific reliability practices be incorporated into the ATC 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 ATC. In addition, a requirement is added for the enhanced documentation of the calculation methodology.
- TRM Standard — Revise existing reliability standards for TRM 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.
- CBM Standard — Consider revising the CBM standard to incorporate the redefinition of CBM as suggested in the LTATF report or to replace this standard as suggested in the minority opinion, [“CBM: Does it help or hinder reliability?”](#).
- The results of these efforts should improve reliability of the bulk power system while promoting greater market transparency for ATC and ATC-related values.

Some 888 Reform NOI commenters have suggested standardizing the methods or inputs into the ATC/CBM/TRM calculations – what is your position on this and what experiences can you cite to support your position?

- Regional ATC methodologies are influenced by the different regional characteristics and limitations, such as voltage, thermal, fault level, stability, multiple contingencies, various generation dispatches, and other parameters that are particular to each region.
- Although ATC calculation techniques may be similar, assumptions used and contingencies analyzed may differ based on the applicable planning or operating criteria.
- The success of the pilot program in the Alliant West area of eastern Iowa demonstrated that these goals can be achieved. During that pilot program, the number of TLR Level 5 events dropped from 138 hours (more than 100 events) during June 2003–March 2004 to 13 hours (2 events) during June 2004–March 2005. Total TLR Level 3, 4, and 5 events dropped from 3,726 hours to 457 hours during the same period.
- NERC believes that through commonality of calculation techniques, assumptions, communication, the exchange of data among the various ATC calculators, and the documentation of methods and assumptions, the calculation of ATC values can be

made more transparent, consistent, and useful to the marketplace without negatively impacting the reliability of the bulk transmission systems.

Minority Opinion on CBM

The purpose of the revision to the CBM standards are to require crisp and clear documentation of the calculation of CBM and make various components of the methodology mandatory so there is more consistency across methodologies.

The NERC ATCT Drafting Team developed and posted, along with its final draft SAR, a minority opinion on CBM, [“CBM: Does it help or hinder reliability?”](#) The minority opinion on CBM is attached for reference as Attachment 3.

The NERC standards drafting process will weigh the minority opinion against other industry opinions such as the [“Transmission Capability Margins and Their Use in ATC Determination”](#) whitepaper in determining what revisions are necessary. The whitepaper is attached for reference at Attachment 4.

Observations on Selected Paragraphs in the NOPR

NERC is providing the following observations on specific paragraphs in the NOPR, not as NERC consensus positions on these issues, but as evidence of the complexity, regional and market differences, and wide range of views within the industry on ATC and ATC-related calculations and applications.

General Observations

The potential for conservatism and lack of consistency in AFC/ATC calculations can be the result of “assumptions” made by individual TSPs. Some examples:

- Counterflow – involves the confidence you have that counterflow transactions will actually be scheduled.
- Base loop flow assumption – this has the potential to show the greatest degree of error.
- Source/sink assumption – when transactions are sourced from a fleet of generators, the assumptions can drastically change results. This is particularly true when the area is widespread.
- CBM/TRM Margins. While the NOPR suggest double counting under certain circumstances, this is a recognized problem and most TSPs have corrected double counting. CBM/TRM standards that require crisp and clear documentation of the calculation of CBM/TRM will address this issue so that TSPs demonstrate how these margins are used appropriately.
- Even with a perfect AFC/ATC process, other factors can influence who gets transmission capacity and who doesn't. To place responsibility for denials/curtailments on the AFC/ATC process is not always accurate.
 - Methodologies to allocate available flowgate capacities or available transfer capacities in the East are generally done apart from the AFC/ATC process. It is part of the rated path methodology in the West.
 - Business practices, such as scheduling practices, can also influence who ultimately gets to use transmission capacity.

- IDC practices to curtail transactions can influence as well because AFC/ATC processes usually try to align with curtailment practices.

Achieving consistency of assumptions requires coordination between TSPs. The NERC draft standard includes requirements for this coordination. Requirements for coordination and sharing of information between entities calculating ATC will help identify when assumptions are in error or need revision.

The sources of many complaints are based on denial of requests and curtailment of sold service. An audit process should indicate the “true” reasons for either denial of service or curtailment of service. NERC will audit entities for compliance with its revised standards to ensure they are coordinating relevant information and consistently applying the regionally accepted methodology. While these audits will ensure conformity to the reliability standards, specific complaints of discrimination would still need to be addressed by the FERC, since complaints regarding discrimination are outside of the ERO enforcement jurisdiction.

Paragraph 116 — refers to the consistency of ATC calculations. It concludes that standardization of data inputs, modeling assumptions and calculation of ATC components will assure nondiscriminatory treatment. NERC supports the improvement of standards to address these issues and is focusing its attention on standardizing the data inputs and assumptions used in ATC calculations.

Paragraph 117 — As Existing Transmission Commitments (ETC) are included in the calculation of ATC, the NERC standards will define this term and require documentation within the ATC calculation methodology being used. The components included in ETC appear to be candidates for business practices. For example, Native Load uses, reserves, and existing commitments for purchases/exchange/deliveries/sales.

Paragraph 119 — Refers to the lack of consistency in CBM set asides. Setting aside CBM on interconnections is intended to provide capacity during generation deficiencies. However, there is no assurance that internal circuits (or flowgates) will have capacity when a generation emergency exists because not all TSPs set aside CBM on internal circuits. Setting aside a portion of transfer capability in the form of CBM and/or TRM is a common approach to provide protection from unexpected conditions. The Commission should consider comments on both the over-subscription of CBM on interconnecting circuits/flowgates and the under-subscription or lack of set aside of CBM on internal circuits/flowgates. How CBM is applied should be included in assumptions in transmission planning processes.

Paragraph 120 —The “[Transmission Capability Margins and Their Use in ATC Determination](#)” whitepaper addresses the horizon within which CBM and TRM should incorporate loss of generation. CBM is a quantity used for next hour. TRM is a quantity used for current operating hour to 59 minutes in. After 59 minutes, CBM is used to address generation loss and the value is dropped from ATC calculations. For example, $ATC \text{ for current hour} = TTC - ETC - TRM$. In the current hour, the TRM has a

consideration for loss of generation and it should adhere to following unifying characteristics:

- The beneficiary of this margin is the “larger community” with no single, identifiable group of users as the beneficiary.
- The benefits of TRM extend over a large geographical area and over multiple transmission providers and it is the result of uncertainties that cannot reasonably be mitigated unilaterally by a single transmission provider or regional entity.

$ATC \text{ for next hour} = TTC - ETC - TRM - CBM$. TRM for the next hour should not include uncertainties for generation loss as those will be incorporated in the CBM. The benefit that Load Serving Entities (LSEs) receive from CBM is the sharing of installed capacity reserves elsewhere in the interconnection, which translates into a reduced need for installed generating capacity. The revised standards for TRM will describe assumptions for transmission contingencies on a broad basis and the CBM standard will describe assumptions for generation contingencies identified for ATC calculations beyond 1 hour. Once the NERC standards are finalized, there will be clear standards to address when these components are used.

Paragraph 121 — Refers to the need for TSPs and TOs to plan their systems using the same assumptions used for selling transmission capacity. Being conservative when evaluating transmission service requests but ignoring strict limits when planning/building the system is inappropriate. Planning assumptions and AFC/ATC calculation assumptions should be consistent.

Paragraphs 122 through 129 — Refers to data exchange and transparency issues.

Proposed NERC standards will adequately address these issues.

Paragraphs 142 through 170 — With regards to CBM, the Commission has proposed several alternatives. NERC expects that through the NERC NAESB Procedure for Joint Standards Development and Coordination and through open forums such as the proposed FERC technical conference that the issue will be settled.

Paragraphs 171 through 179 — Refers to the requirement for transparency. NERC's revised standards will address transparency.

Summary and Recommendation

NERC will take into account the issues raised by the Commission in its NOPR and will continue to keep the Commission closely apprised of its work on ATC and ATC-related and CBM and TRM-related reliability standards, including the coordination of those activities with the respective efforts at NAESB.

NERC agrees that, following the close of the comment period on the subject NOPR, the Commission would benefit from holding a technical conference on ATC and ATC-related and CBM and TRM-related issues to allow all interested stakeholders to explain their positions. NERC is very interested in participating in such a conference to

provide its perspectives on the reliability aspects of these issues and to update the Commission on the status of its ATC/TTC and CBM/TRM standards development activities.

NERC thanks the Commission for affording it the opportunity to report on its current ATC-related activities and to comment on the status of its standards development in this area. NERC looks forward to continuing to work with the Commission and the industry on these matters.

Respectfully submitted,

NORTH AMERICAN ELECTRIC
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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	<input type="checkbox"/>	New Standard
Primary Contact	Larry Middleton SAR Drafting Team Chair	<input checked="" type="checkbox"/>	Revision to existing Standard
Telephone	(317) 249-5447	<input type="checkbox"/>	Withdrawal of existing Standard
Fax			
E-mail	lmiddleton@midwestiso.org	<input type="checkbox"/>	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 <i>(Check box for each one that applies by double clicking the grey boxes.)</i>		
<input checked="" type="checkbox"/>	Reliability Authority	Ensures the reliability of the bulk transmission system within its Reliability Authority area. This is the highest reliability authority.
<input checked="" type="checkbox"/>	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
<input checked="" type="checkbox"/>	Interchange Authority	Authorizes valid and balanced Interchange Schedules
<input checked="" type="checkbox"/>	Planning Authority	Plans the bulk electric system
<input checked="" type="checkbox"/>	Resource Planner	Develops a long-term (>1year) plan for the resource adequacy of specific loads within a Planning Authority area.
<input checked="" type="checkbox"/>	Transmission Planner	Develops a long-term (>1 year) plan for the reliability of transmission systems within its portion of the Planning Authority area.
<input checked="" type="checkbox"/>	Transmission Service Provider	Provides transmission services to qualified market participants under applicable transmission service agreements
<input checked="" type="checkbox"/>	Transmission Owner	Owens transmission facilities
<input checked="" type="checkbox"/>	Transmission Operator	Operates and maintains the transmission facilities, and executes switching orders
<input type="checkbox"/>	Distribution Provider	Provides and operates the “wires” between the transmission system and the customer
<input checked="" type="checkbox"/>	Generator Owner	Owens and maintains generation unit(s)
<input checked="" type="checkbox"/>	Generator Operator	Operates generation unit(s) and performs the functions of supplying energy and Interconnected Operations Services
<input checked="" type="checkbox"/>	Purchasing-Selling Entity	The function of purchasing or selling energy, capacity and all necessary Interconnected Operations Services as required
<input checked="" type="checkbox"/>	Market Operator	Integrates energy, capacity, balancing, and transmission resources to achieve an economic, reliability-constrained dispatch.
<input checked="" type="checkbox"/>	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.)	
<input checked="" type="checkbox"/>	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.
<input type="checkbox"/>	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.
<input checked="" type="checkbox"/>	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.
<input type="checkbox"/>	4. Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented.
<input type="checkbox"/>	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems.
<input checked="" type="checkbox"/>	6. Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified and have the responsibility and authority to implement actions.
<input type="checkbox"/>	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 been 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 commitments”).
- 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. : $ATC = TTC - \text{committed uses} - CBM - TRM$. (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	<p>NAESB proposed Business Practice for a single Business Practice Standard to be developed related to:</p> <p>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:</p> <p>1) the processing of transmission service requests, which use TTC/ATC/AFC, in coordination with NERC changes to MOD 001,</p> <p>2) 1) the processing of transmission service requests, which use CBM/TRM.</p>
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 frequency¹ 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). The update frequency is daily. 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 daily 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 : The update frequency is hourly.

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

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. The update frequency is daily. 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.

(standard drafting team to develop procedures for audit to ensure adherence to stated methodology – see Appendix 3)

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:

$$\text{ATC} = \text{TTC} - \text{Existing Transmission Commitments} - \text{CBM} - \text{TRM}$$

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:

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

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)
<u>Name</u> ATCT SAR Drafting Team atctdt_plus@nerc.com	<input type="checkbox"/> New Standard <input type="checkbox"/>
<u>Primary Contact</u> Larry Middleton SAR Drafting Team Chair	<input type="checkbox"/> Revision to existing Standard(s) <input checked="" type="checkbox"/>
<u>Telephone</u> (317) 249-5447 <u>Fax</u>	<input type="checkbox"/> Withdrawal of existing Standard <input type="checkbox"/>
<u>E-mail</u> lmiddleton@midwestiso.org	<input type="checkbox"/> Urgent Action <input type="checkbox"/>

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

Applicability to be determined by standard drafting team.

Reliability and Market Interface Principles

Applicable Reliability Principles <i>(Check boxes for all that apply by double clicking the grey boxes.)</i>	
<input checked="" type="checkbox"/>	<u>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.</u>
<input type="checkbox"/>	<u>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.</u>
<input checked="" type="checkbox"/>	<u>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.</u>
<input type="checkbox"/>	<u>Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented.</u>
<input checked="" type="checkbox"/>	<u>Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems.</u>
<input checked="" type="checkbox"/>	<u>Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified and have the responsibility and authority to implement actions.</u>
<input type="checkbox"/>	<u>The security of the interconnected bulk electric systems shall be assessed, monitored and maintained on a wide area basis.</u>
Does the proposed Standard comply with all of the following Market Interface Principles? <i>(Select 'yes' or 'no' from the drop-down box by double clicking the grey area.)</i>	
<u>The planning and operation of bulk electric systems shall recognize that reliability is an essential requirement of a robust North American economy. Yes</u>	
<u>An Organization Standard shall not give any market participant an unfair competitive advantage. Yes</u>	
<u>An Organization Standard shall neither mandate nor prohibit any specific market structure. Yes</u>	
<u>An Organization Standard shall not preclude market solutions to achieving compliance with that Standard. Yes</u>	
<u>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</u>	

Related Standards

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

Related SARs

SAR ID	Explanation
_____	<u>Resource Adequacy SAR/Standard</u>
_____	_____
_____	_____
_____	_____
_____	_____
_____	_____
_____	_____
_____	_____
_____	_____

Regional Differences

Region	Explanation
<u>ECAR</u>	_____
<u>ERCOT</u>	_____
<u>FRCC</u>	_____
<u>MRO</u>	_____
<u>NPCC</u>	_____
<u>RFC</u>	_____
<u>SERC</u>	_____
<u>SPP</u>	_____
<u>WECC</u>	_____

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.

CBM: Does it help or hinder reliability?

*This is **the minority opinion** of the ATCT Drafting Team. Although this paper may not apply to all Transmission Service Providers (TSPs), it does apply to several in the eastern interconnection.*

The design of the Capacity Benefit Margin (CBM) product as it is today does little to enhance reliability. In fact, one could deduce that the preservation of CBM actually hinders reliability. CBM is intended to be an instrument to ensure the availability of transmission during a local generation resource shortage, but until the industry can agree to coordinate these efforts, the result may be making things worse instead of better. In fact, current interpretations of the calculation and use of CBM by several TSPs cause several concerns:

1. CBM is a partial path reservation without a designated generation source.

CBM is an import quantity only. There are no arrangements between TSPs for the reservation and use of CBM on neighboring transmission systems. This means that when CBM is being utilized on a TSP's system during emergency conditions, there still needs to be arrangements made with all external TSPs for the use of *their* transmission systems. There is absolutely no assurance that the transmission service will be available on that other TSP's system. Furthermore, since emergencies occur in real-time, firm service is not available due to timing requirements. In fact, the only service that is available is non-firm hourly service or non-firm secondary service. With TLR occurrences being the rule, rather than the exception, the risk of curtailment of the emergency import is very probable due to the use of non-firm transmission. There are currently no provisions in either the TLR procedure or any TSPs tariff that allow for special treatment for external Load Serving Entities (LSEs) to use their system for emergency (CBM) purposes. In addition to the transmission availability risk, there is also no assurance that generation resources will be available on the interfaces (or impact flowgates) on which CBM is reserved.

2. Use of CBM can restrict adequate resource planning.

Another problem with the current CBM methodology employed by some TSPs is that a LSE that expects to have a capacity deficit is now less likely to be able to make a long-term capacity purchase to ensure resource adequacy. The shortage can almost be seen as a self-fulfilling prediction. The LSE may be forecasting a shortage based on a Loss of Load Expectation (LOLE) calculation, so CBM is added to the interface (or flowgates) to ensure deliverability during emergencies. Since CBM is on the interface (or flowgates), the LSE can not get firm transmission service to purchase capacity and is forced into an emergency situation. This seems to be an illogical approach and does not appear to be in the best interest of the LSEs who are trying to hedge against generation shortages and price risk.

The opposite problem can also occur. The LSE (or TSP) may calculate a CBM of 100 MW to maintain the correct LOLE and later the LSE can make a firm transmission and generation purchase (import) of 25 MW. The CBM should actually be decremented by 25 MW down to 75 MW. However, the CBM may not be calculated every time an LSE makes a firm capacity purchase. In this case, the CBM requirement would be 75 MW, but the TSP is reserving 100 MW. This would limit others from making firm economic purchases to hedge against price risk. Again, this is not in the best interest of the LSEs.

3. LSEs that can choose which interfaces to reserve CBM could restrict competition in that area.

Some TSPs have affiliated LSEs and allow LSEs to determine which interfaces utilize CBM. A TSP's decision to set aside transmission capacity for emergency imports pursuant to either long-term reserve sharing arrangements or probabilistic LOLE calculations reduces the firm import capacity available to its competitors. Whether to reduce ATC/AFC for a CBM reservation, at which interface and in what amount, is a competitively significant decision that is driven by commercial choices which may be made by the large incumbent LSE. It reflects tradeoffs made by the LSE (and its generation/merchant function) as to reliance on internal vs. external generation for sources of energy and reserves. This procedure invites abuse.

4. CBM should not be used as a substitute for “real” reserves.

There could be cases where LSEs are physically “short” real reserves, but use CBM to justify resource adequacy.

Clearly, the current use of CBM has questionable reliability value. The lack of transparency, standardization, and auditable definition, coupled with the absence of procedures for CBM to be reserved and paid for like other transmission reservations, invites abuse. It also may provide a false sense of security that CBM will provide the transmission needed to import emergency generation.

Proposed Solution

The current use of CBM by some TSPs should be discontinued. Today, Capacity Benefit Margin (CBM) is defined as:

The amount of firm transmission transfer capability preserved by the transmission provider for load-serving entities (LSEs), whose loads are located on that transmission provider's system, to enable access by the LSEs to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for an LSE allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability

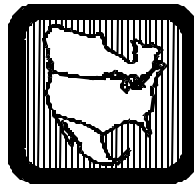
requirements. The transmission transfer capability preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies.

For some LSEs, the current use of CBM may be better than no CBM (although it may be harming some LSEs). Instead of setting aside CBM on a TSP's system as a reliability quantity without the appropriate charges, it would be more reasonable and reliable to require the LSE(s) to obtain a firm transmission path from source to sink and obtain contracts from outside generation to ensure resource adequacy.

Those entities that currently allow for the use of CBM to reduce generation reliability requirements would be better served by this approach than the CBM approach which "assumes" that uncommitted external resources will be there when you need them. This ensures that not only is transmission available in the event of an emergency, but generation will also be available because it is contracted for. It also assigns the cost of the transmission reservations and the cost of capacity to the LSE(s) who directly benefit. A CBM "assumption" about external capacity may be an unrealistic expectation in this time of shrinking capacity margins.

Transmission Capability Margins and Their Use in ATC Determination

White Paper



Prepared by the North American Electric Reliability Council
Available Transfer Capability Working Group

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Background

In June of 1996, the North American Electric Reliability Council (NERC) approved a document entitled “*Available Transfer Capability Definitions and Determination*” as a framework for determining Available Transfer Capability (ATC) to satisfy both Federal Energy Regulatory Commission (FERC) requirements and industry needs. When approving the document, NERC recognized that it provides only an initial framework and may require expansion and modification as the industry gains experience. In defining the components that make up ATC, a number of new terms were introduced. Among these terms were two transmission margins to recognize uncertainty inherent in the interconnected power system. These two margins are known as the Transmission Reliability Margin (TRM) and the Capacity Benefit Margin (CBM). There is currently a large disparity in the magnitude of the margins applied by transmission providers across the Interconnections. Because of this disparity, especially in the quantification of CBM, the Available Transfer Capability Working Group (ATCWG) sponsored a symposium in January 1998. This symposium was designed to provide a forum to explore the different margin determination methodologies, and to encourage a convergence of the methodologies within and among the Regions. The purpose of this paper is to better define the margins and to foster a consistent approach for their determination and application.

Although both TRM and CBM are defined in the *Available Transfer Capability Definitions and Determination* document, the NERC Engineering and Operating Committees (EC/OC) (now referred to as the Adequacy and Security Committees (AC/SC), respectively) determined that the calculation and application of these margins requires further clarification beyond what is included in the ATC document. To this end, the EC/OC charged the ATCWG with the task of preparing a report to add needed detail to TRM and CBM methodologies. This document is in response to that request. Within this document, the reader will find definitions for both TRM and CBM that differ from the original definitions found in the NERC ATC document. It is the position of the ATCWG that these new definitions and descriptions should replace those in the 1996 document, in order to achieve a common understanding and approach for the need and quantification of these margins.

This paper has been written with the assumption that the reader is familiar with the NERC ATC document and that the legitimacy of the transmission margins has been established. Therefore, this paper is not intended as a justification of the need for transmission margins, but is rather a clarification and redefinition of how these margins are to be determined, allocated, and applied.

Purpose

This paper and the recommendations herein will be presented to the NERC AC for its consideration. If approved, this paper will serve as the foundation of NERC Planning Standards related to CBM and TRM and will be incorporated as an appendix to the 1996 ATC document. The intention of this effort is to reach consensus on the determination and quantification of TRM and CBM. At the very least, the Regions are encouraged to promote a common TRM and CBM determination methodology. An earlier version of this document was published on the NERC web site in January 1999 for public comment.

TRANSMISSION RELIABILITY MARGIN

Definition

Transmission Reliability Margin (TRM) is to be defined as:

The amount of transmission transfer capability necessary to provide a reasonable level of assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and its associated effects on ATC calculations, and the need for operating flexibility to ensure reliable system operation as system conditions change. All transmission system users benefit from the preservation of TRM by transmission providers.

Generally, the uncertainties associated with the operation of the interconnected electric system increase as the time horizon increases. These uncertainties can be attributed to weather conditions, forced and scheduled transmission outages, and generation unavailability. In the longer term, the health of the economy and the economics of generation will greatly influence the level and location of demand and electric resources. Because of these conditions, the uncertainties or “inaccuracy” of the TTC and ATC values also increase with time. The further into the future that TTC/ATC values are projected, the greater the uncertainty. For instance, future customer demands and generation dispatches are often quite uncertain, which greatly impacts the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. Similarly, future electric power transactions are inherently uncertain and can have significant impacts on transmission system loadings. Compounding this problem is the difficulty that transmission systems not contractually associated with a particular transaction can experience in trying to quantify its impact on their respective systems. Therefore, the amount of TRM required is time dependent, generally with a larger amount necessary for longer time horizons than for near-term time periods.

Components of TRM

Transmission providers must consider the ATC margin components described in this section in their TRM calculations. Transmission providers may set all or some of the component values to zero. However, documentation that supports the quantification of TRM (including zero TRM values) is necessary. Transmission providers are advised to use caution in developing estimates of each component and subsequently combining all components together, as such an approach may result in TRM values that are unnecessarily large.

While the components that comprise TRM may be easily identifiable, the calculated values of these components may change depending upon experience and forecasts of system conditions. Transmission providers must address the TRM components for applicability to their systems. The methodology used to derive TRM and its components must be documented and consistent with published planning criteria, and must not account for uncertainties already accounted for elsewhere in the ATC determination. A TRM is considered consistent with published planning criteria if the same components that comprise it 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 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 components of TRM have the following unifying characteristics:

- The beneficiary of this margin is the “larger community” with no single, identifiable group of users as the beneficiary. The benefits of TRM extend over a large geographical area and over multiple transmission providers.
- They are the result of uncertainties that cannot reasonably be mitigated unilaterally by a single transmission provider or Regional entity.

Components that are to be considered in the determination of TRM:

- **Aggregate Load Forecast Error C** The load forecast is subject to error, as is any forecast. The inability to precisely predict a future load level and the subsequent loadings experienced on transmission system elements requires a reasonable quantity of transmission capacity to remain “uncommitted.” This “uncommitted” transmission resource, when actually needed in real time, benefits the entire community by helping to ensure that the reliability of the entire Interconnection is maintained.
- **Load Distribution Error C** Similar to an “error” in the aggregate load forecast, the distribution of the load will also vary the loading of system facilities. Maintenance of a reasonable quantity of “uncommitted” transmission capacity will help to ensure that the reliability of the entire Interconnection is maintained.
- **Variation in facility loadings due to the balancing of load and generation within a control area C** System load is a dynamic quantity. Generation increases and decreases in response to these load variations. A reasonable margin to account for this variation will help to ensure that the reliability of the entire Interconnection is maintained.
- **Forecast uncertainty in system topology C** Reasonable allowance for the impact of the myriad outages that may occur day-to-day also benefits the entire community. Most TTC calculations performed for the planning horizon are based upon the most critical single contingency and do not account for the base system condition including some level of facility outages.
- **Allowances for parallel path “loop flow” impacts C** Each network element is subject to parallel path flows. These parallel path flows are the result of transmission service transactions that are not explicitly scheduled on the transmission system of a particular transmission provider. Since these flows are not scheduled on their system, a transmission provider may not be aware of or able to explicitly account for the impact of other parties’ transactions on his own system. Therefore, maintenance of a reasonable quantity of “uncommitted” transmission capacity will help to ensure that the reliability of the entire

Interconnection is maintained. Note that proper coordination of basic system data between transmission providers should minimize the magnitude of this component.

- **Allowances for simultaneous path interactions C** Transmission paths may interact and not be capable of operation at each path's full transfer capability. The secure operation under such situations can be described by a nomogram. Nomograms may also be used to indicate the variability in capability of transmission paths as dictated by temperature, load level, available reactive support, and other factors. TRM may be used to account for the difference between the firm capability of a transmission path and the path's maximum capability.
- **Variations in generation dispatch C** The generation dispatch will vary for reasons such as the number of units having load following capability, generation availability, generation conditions within the generating plant, and economics. Maintenance of a margin helps account for the impacts of these variations upon the transmission system.
- **ShortBterm Operator Response/Operating Reserves C** Following a contingency, system operators take immediate actions, either individually or in concert with other operators, to maintain the reliability of the transmission system. Transmission capacity must remain available to allow for operator flexibility immediately following such a contingency. To maintain reliability, agreements between control areas exist to implement a quick and coordinated response following a transmission or generation contingency. Operating reserve programs (at least in part) are designed to provide transmission operators with procedures needed to maintain reliability. Therefore the transmission capacity needed to access operating reserves or to implement operating reserve sharing agreements for the period immediately following the contingency before the market can respond (currently up to 59 minutes following the contingency) is a TRM component. Any portion of a reserve sharing program that extends into the market reaction time (currently beyond 59 minutes following the contingency), should be included in CBM.

Operating reserves are additional capacity either from generators that are on-line (loaded to less than their maximum output, and available to serve customer demand immediately should a contingency occur), or from generators that can be used to respond to a contingency within a short period of time (usually ten minutes). The existence of interconnections allows for the sharing of operating reserves between Control Areas, which reduces the amount of operating reserves each Control Area must carry on its own. The loss of a generating unit cascading into multiple system disturbances or load curtailments can be avoided by having adequate operating reserves. Operating reserve sharing programs have been implemented by a number of areas to provide reliability and economic benefits to the members of the group. As long as membership in these reserve-sharing groups remains open, they also provide benefit to the entire interconnected system. Operating reserves are provided for a limited time period, typically less than one hour. The consideration of operating reserves as a TRM component (unless explicitly modeled in TTC, as described later) recognizes that current procedures and technology limit the ability of the marketplace to replace a sudden loss of generation in real time. A quick replacement of an unexpected loss from a generation resource is necessary to maintain operating reliability performance levels. In fact, NERC's Interconnected Operations Services Implementation Task Force (IOSITF) has recommended that operating reserve

sharing programs be designated as community Interconnected Operations Services that benefit the entire network. Therefore, although operating reserve is a generation quantity, operating reserves and operating reserve sharing agreements up to the time the market can respond (59 minutes or less) benefits the entire interconnection and must be considered a component of TRM.

There are two prevalent methods for determining the operating reserves component of TRM. The first method explicitly models operating reserves in the calculation of TTC by replacing lost generation based on a call for operating reserve sharing. If the generator contingency is more restrictive, the limit, due to implementation of the operating reserve sharing, sets the amount of TTC. If the transmission contingencies are all more restrictive, the transmission contingency limit will set the amount of TTC. If a generator contingency occurs, resulting in the need to access operating reserves, it will produce lower loadings than the transmission contingency. This method may be appropriate when monitoring all transmission facilities in the Interconnected system.

The second method simulates the loss of individual generators with replacement power modeled as a call for operating reserve sharing via power flow analyses. The maximum increased flow on the interface or flowgate becomes the operating reserve sharing component of TRM. This method may be more appropriate when monitoring a limited number of facilities or flowgates similar to the TRM applied by interface.

TRM Application Methodologies

It is not the purpose of this paper to describe the detailed process of the calculation methodologies by which TRM is determined, but rather to delineate the thought process to derive the TRM quantity. Since TRM is a margin of transmission transfer capability withheld from firm and/or nonfirm transmission commitments for the benefit of the entire community, it is not necessarily a uni-directional quantity. There are two prevalent approaches to account for uncertainty as a TRM value, although there can be variations within these approaches. Typically, TRM is either calculated via a simple facility rating reduction (in percent of ratings) or a transfer capability quantity applied (in MW) at specific interfaces.

- **TRM applied by rating reduction** — For systems in which the distribution of uncertainty among all of its facilities is relatively uniform, a TRM applied to all the transmission provider's system facilities may be appropriate. In this case, the TRM is applied against the facility ratings themselves and is measured as a percentage reduction of facility ratings. The rating reduction is typically 2–5% and may increase over an extended time horizon.

This determination is typically accomplished by a two-step method:

1. The TTC and ATC values are determined using the full “customary” (normal or emergency ratings as appropriate) ratings (i.e., assume that TRM is zero).
2. Determine the ATC using facility ratings that are reduced from the “customary” ratings. The TRM (in terms of MW of transfer capability) is simply the algebraic

difference between the ATC values determined using the “customary” ratings and the ATC values determined using reduced ratings.

- **TRM applied by interface C** In systems where uncertain contributions can be associated with specific interfaces or flowgates, a TRM applied to specific critical interfaces or flowgates may be appropriate. Systems that apply TRM in this manner typically would be able to quantify the uncertainty associated with TRM components through the use of historical transmission loading analysis. In this case, the TRM is applied against a particular facility or set of facilities and is measured as a megawatt reduction in transfer capability. The TRM applied in this manner is relatively constant but may change based on the actual experience.

Although the general methods to apply TRM differ in application and approach, they both serve to quantify a reasonable amount of transfer capability margin to provide the operating flexibility to ensure reliable system operation as system conditions change. However, the applications of TRM are related in that the amount of TRM is a factor of the limiting facility’s response for the particular transfer.

TRM should not be applied to paths limited by contract-based interconnection ratings or other contractual reasons (i.e., the path is “scheduling limited”) since the capability of such a path is not subject to the uncertainties for which TRM is intended. The only exception is when a transmission provider incorporates a non zero operating reserve sharing component into TRM, and then must subtract this amount from the contractual capability of the facility/ties in question.

TRM may be sold on a nonfirm basis to the extent that the transmission provider feels it can do so without degrading system security.

Capacity Benefit Margin

Definition

Capacity Benefit Margin (CBM) is to be defined as:

The amount of firm transmission transfer capability preserved for Load Serving Entities (LSEs) on the host transmission system where their load is located, to enable access to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for a LSE allows that entity to reduce its installed generating capacity below what may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission capacity preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies.

Unlike TRM, the direct beneficiaries of CBM can be identified. These beneficiaries are the LSEs that are network customers (including native load) of a host transmission provider. The benefit that LSEs receive from CBM is the sharing of installed capacity reserves elsewhere in the

Interconnection, which translates into a reduced need for installed generating capacity and ultimately, lower rates for their customers.

CBM is the translation of generator capacity reserve margin determined by (or for) the LSEs within a host transmission provider into a transmission transfer capability quantity. It is the transmission provider's responsibility to make this translation and as such, the transmission provider may apply discretion in determining this quantity. The planned purchase of energy to serve network load (including native load) and/or meet required/recommended generation reserve levels are not to be included in the CBM quantity. These planned purchases actually reduce the total CBM quantity. For example, if an LSE requires 4,500 MW dependence on external resources and plans the explicit purchase of 1,000 MW, then the total CBM is 3,500 MW.

Generally, CBM is not a “real-time” margin that “exists” in the current hour, but is a margin that extends from one hour into the future. The amount of CBM to be applied is in the form of a continuum in which the CBM is at a maximum amount in the longer term and a minimum level beginning with the next hour. This assumes that the uncertainty associated with generation availability decreases as the time horizon is reduced. In the current hour, generation capacity benefits in the form of operating reserves are considered part of the TRM. Operating reserves are provided for a limited time period, typically less than one hour. The recognition that operating reserves are a transmission reliability component acknowledges that current procedures and technology limit the ability of the marketplace to replace a sudden loss of generation in real time. A quick replacement of an unexpected loss of a generation resource is necessary to maintain operating reliability performance levels. Since quick replacement of lost resources benefits the entire Interconnection, operating reserves (for the time period between the contingency event and operator action to replace this power) provide reliability benefits beyond the specific LSE being served from that resource and is not considered part of CBM. Transmission capacity needed to accommodate generation reserves consistent with generation reliability criteria that are above the required operating reserve level would be included in CBM.

Generation reserve sharing programs extending beyond 59 minutes are used to meet generation reliability criteria. The NERC IOSITF has recommended that replacement power following a generator contingency that extends beyond a reasonable operator response time (typically one hour or less) be designated as an Interconnected Operations Service that benefits specific LSEs and not the entire community therefore, generation reserve sharing uses that extend beyond 59 minutes are *not* to be included in TRM and are more appropriately accounted for in CBM.

Unlike TRM, CBM benefits an identifiable set of transmission system users: the LSEs. As such, CBM is only to be preserved as an import quantity (a uni-directional quantity) on the system of the host transmission provider. In determining the amount of CBM to apply, the requirements of all customers entitled to its use must be taken into consideration. Transmission providers have the responsibility to determine CBM, but must do so with the input of all LSEs entitled to a portion of the CBM.

Transmission providers must consider their obligations, if any, to supply CBM to interruptible customers or to customers that have contractual provisions to arrange their purchases of

generation resources during a capacity deficiency (sometimes referred to as “buy-through” customers). It may be prudent to include buy-through customers in determining the generation reserve requirements of a host transmission provider, since they are retail native load customers and have the option to purchase from outside the system at their discretion. Interruptible customers should generally not be considered, since these customers do not have an option to continue their consumption when ordered to curtail by control area operators. It is prudent to include the same portion of the interruptible load in the CBM determination that is expected to be available during a CBM event, recognizing that not all interruptible loads will be at maximum levels when a CBM event occurs.

CBM Calculation and Allocation

The methodology used to derive CBM must be documented and consistent with published planning criteria. A CBM is considered consistent with published planning criteria if the same components that comprise the 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 Generation Reserve Requirement can be determined via either deterministic or probabilistic methods.

- **Probabilistic Methodology** — Probabilistic calculation methods, such as loss of load probability, have inputs such as unit forced outages, maintenance outages, minimum downtimes, load forecasts, etc. A typical benchmark is a generation reserve level to achieve a probabilistic loss of load expectation of 0.1 day per year.
- **Deterministic Methodology** — Deterministic methods typically are centered on maintaining a specified reserve or capacity margin, or may be based upon surviving the loss of the largest generating unit. Typical benchmarks for the determination methodology would be a multiple of the largest generation unit within the transmission provider’s system.

Whether probabilistic or deterministic methods are used to determine the generation reserve requirement, the criteria applied must be consistently applied by the transmission provider to all LSEs. In some cases, it may be appropriate to apply both deterministic and probabilistic methods for the determination of generation reserve requirements, depending upon the time frame under consideration. For example, in the very near time frame, the degree of uncertainty associated with generating unit forced and maintenance outages should be low and deterministic methods for the calculation of generation reserve requirements may be applied. In this example, for the longer-term time frame, probabilistic methods may be applied due to the number of variables and the uncertainty associated with them.

The determination of CBM for an LSE is a three-step process:

- 1) The amount of additional external generating capacity necessary to achieve a target reliability level (e.g., 0.1 day/year loss of load expectation) must be determined.

- 2) The total amount of transmission transfer capability necessary to import the external generating reserve requirement must be determined from the amount of required external generating capacity (less the TRM component for operating reserves).
- 3) This total amount of transmission transfer capability must be allocated to the specific transmission system interfaces or paths over which the imported power may flow.

These three steps can be accomplished either sequentially or simultaneously. Sequential determination often relies on deterministic rules. For example, the needed external generating capacity might be set at the capacity of the largest internal plant, the total CBM might be set at two times that amount, and the allocation among three interfaces might be set as 60/20/20%, based upon historical experience. Simultaneous determination can be accomplished with a probabilistic model, which includes both generation and transmission representation.

Regardless of the process used, the transmission provider must ensure that:

- a) The method used to arrive at the amount of external generation needed is consistent with applicable reliability criteria.
- b) If the total transmission capacity reserved as CBM on all interfaces exceeds the external generation reserve requirement (less the TRM component for operating reserves), it is reasonable and justified.
- c) The allocation of the total CBM to individual interfaces, or source points, is consistent with available external generation resources, known transmission limitations, and historical transfer patterns during actual emergency generating capacity deficiency events.

The allocation of CBM to the host transmission provider interface(s) must be based solely on the generation reserve and projected availability of outside sources (the strength of the transmission interfaces needed to import the CBM requirement allocation) and the historical availability of outside resources. The preservation of CBM on the importing transmission provider's system does not ensure the availability of transmission transfer capability on other systems, but relies on the diversity of generation and transmission resources that may be available on the Interconnection during a generation emergency. Therefore, the availability of third-party transmission transfer capability must be a consideration in the allocation of CBM.

CBM may be allocated to each Interconnection interface and subtracted from the calculated TTC. In doing so, the actual flow impacts of CBM reservations may not be taken into account. In some cases, it may be appropriate for the transmission provider to allocate CBM to each interface in such a manner that the sum of the allocations to all the interfaces exceeds the generation requirement used to determine the CBM. This is to recognize the low probability of all resources upon which dependency is projected being available simultaneously.

CBM may also be allocated to a transmission system by modeling the generation reserve requirements as base transfers and examining, via power flow analysis, the impacts of the

modeled generation reserve requirements upon the TTC of the path being studied. This method accounts for the predicted flow impacts of the CBM preservation.

If contractual rights on an interface or path form the limit for the path for which source points for a CBM requirement are being modeled, it is not appropriate to model an import in excess of the contractual “scheduling” limit. The net schedule on a contractually limited interface is currently limited to the ownership rights of the seller and is not based upon actual flow. Modeling a base import amount in excess of the contract path limit will not reflect the appropriate scheduling limit on the interface in this case. The use of this method on a contractually limited interface may result in an inability of the LSE to schedule the required CBM amount on that specific path, as illustrated in the following example:

Example: An interface between Area A and Area B is limited by contract to 500 MW in the direction from A to B, and there is no network limit less than 500 MW. In this case, the maximum TTC is limited to 500 MW from A to B. At no time should more than 500 MW be scheduled across the interface from A to B (note: systems offering congestion management options are permitted to sell, but not schedule, nonfirm above the contractual limit). If the CBM requirement from A to B is 200 MW, this must be subtracted directly from the 500 MW TTC. If the actual flow impacts of the 200 MW are less than the requirement (assume it is 125 MW) and are all that is removed from ATC, the transmission provider cannot schedule the entire 200 MW CBM requirement if the interface becomes fully subscribed. The 500, less only the 125, would leave 375 available for firm service. If that becomes reserved, the transmission provider could never schedule the full 200 MW of CBM requirement on that contract path. The LSE would need to secure an alternate contract path for the remaining 75 MW.

CBM is not to be allocated directly to through paths (also known as wheeling) unless one of the interfaces is limited contractually (for the reason above). If CBM is allocated using the base transfers method, the impacts of preserving CBM will be reflected on all paths and any appropriate limits on through paths as a result of CBM allocation on import paths will be accounted for in the TTC calculation.

Use of CBM

CBM may be sold on a nonfirm basis. As with any margin, the generation reserve requirement (and therefore the CBM) should be recalculated as conditions change. If a change (increase or decrease) in CBM on a particular path is prudent due to current or projected conditions, the host transmission provider (and/or the LSE) may change the CBM on the path, provided that there is sufficient firm ATC on that path. If there is not sufficient firm ATC available, the host transmission provider (and/or the LSE) cannot unilaterally displace other existing firm uses of the interface. Regions should establish CBM re-determination schedules.

The use of CBM “in advance” of the near-term horizon must be fully explained by the LSE. CBM is only to be used for capacity deficiency emergency conditions. These conditions should not be driven purely by economic reasons, but rather must be based upon true emergency

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generation deficiencies. CBM should be invoked only after all other options available to the LSE (short of shedding firm load) have been exhausted or should be consistent with the requirements of any applicable reserve sharing group.

It is the position of the ATCWG that both the CBM methodology and values should be made available to customers either via the OASIS or some other publicly accessible site. All transmission users should have access to the CBM methodology of the Region and/or the individual transmission provider as well as the CBM values for all commercial paths.

ASSUMPTIONS RELATED TO THE DETERMINATION OF TRM/CBM

It is helpful in determining TRM and CBM to be cognizant of factors that must be considered in developing ATC, but are not deemed appropriate components of TRM and CBM.

- 1) At a minimum, all single transmission and generator contingencies shall be included in the determination of TTC, provided the contingencies are consistent with appropriate published NERC, Regional, subregional, power pool, and individual system reliability criteria.
- 2) Inertial response (or frequency bias) to generator contingencies is considered in TTC calculations.
- 3) All known generation and transmission outages are incorporated into ATC calculations for both firm and nonfirm transmission service.
- 4) Thermal ratings applied in the determination of TTC should be contingency-based (e.g., emergency) ratings.

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