DAVID N. COOK
General Counsel

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

May 17, 2002

Hon. Magalie R. Salas, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Dear Secretary Salas:

Capacity Benefit Margin in Computing Available Transmission Capacity
Docket No. EL99-46-000

Enclosed for filing in the above captioned proceeding, on behalf of the North American Electric Reliability Council ("NERC"), are an original and 14 copies of the "Report on Actions of the North American Electric Reliability Council Concerning Available Transmission Capacity."

Please time stamp the duplicate original and return it to me in the enclosed self-addressed envelope. A copy of this filing has been sent to all parties on the service list maintained by the Secretary in Docket No. EL99-46-000. In addition, NERC is posting this filing on its web site. If you have any questions regarding this filing, please contact the undersigned.

Thank you.

Very truly yours,

David N. Cook

Enclosures

Phone 609-452-8060 ¦ Fax 609-452-9550 ¦ www.nerc.com

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Capacity Benefit Margin in	)	
Computing Available	)	Docket No. EL99-46-000
Transmission Capacity	)	

REPORT ON ACTIONS OF THE
NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL
CONCERNING AVAILABLE TRANSMISSION CAPACITY

The North American Electric Reliability Council ("NERC") files this report on recent actions it has taken concerning standardization of the calculation of available transmission capacity. [1]

The Commission had ordered jurisdictional transmission providers, working through NERC, to develop a standardized methodology for deriving capacity benefit margin, one of the components in calculating available transmission capacity. Capacity Benefit Margin in Computing Available Transmission Capacity, 88 FERC ¶ 61,099 (1999).

On December 22, 1999, NERC informed the Commission that the six of its ten Regional Reliability Councils that use capacity benefit margin values in their determination of available transfer capability had developed Regional capacity benefit margin methodologies. NERC also reported that it was continuing with its development of more detailed and refined capacity benefit margin, available transfer capability, and related standards.

NERC has now completed the standards work it had underway on the capacity benefit margin issue and related standards. Following the NERC standards development process, which included multiple opportunities for public comment, field testing, and approval by NERC's Planning Committee and Market Interface Committee, NERC's

[1] The Commission uses the term "Available Transmission Capacity" to label the information that is to be made accessible to all transmission users as an indication of the available capability of the interconnected transmission networks to support additional transmission service. NERC uses the term "Available (Transmission) Transfer Capability" to avoid confusion with individual transmission line capacities or ratings.

Board of Trustees approved revised planning standards for total transfer capability, available transfer capability, capacity benefit margin, and transmission reserve margin in February 2002. (Attachments 1 and 2).

These revised planning standards provide a standardized framework under which total transfer capability, available transfer capability, capacity benefit margin, and transmission reserve margin values must be determined within each Region. It is in the application of the specific requirements and measurements of the standards that each Regional methodology must address where differences arise. In recognition that some differences are acceptable, and even necessary in certain cases, the standards require that these differences be fully disclosed and explained to all who use the transmission systems.

Of particular concern to NERC's Board of Trustees at the February 2002 meeting were the comments of the Midwest ISO, which operates in four different NERC Regions, with the potential of being required to comply with four different Regional methodologies. As a part of approving the revised standards, the Board requested the four Regions involved (East Central Area Reliability Coordination Agreement, Mid-America Interconnected Network, Mid-Continent Area Power Pool, and Southwest Power Pool) to work with the Midwest ISO to develop a single calculation methodology for use by the Midwest ISO in determining total transfer capability, available transfer capability, capacity benefit margin, and transmission reserve margin values. The Board also asked for a report from these Regions at its June 2002 meeting on what that single methodology is or why such a methodology has not been achieved.

The revised standards are a significant improvement over individual transmission provider calculations of total transfer capability, available transfer capability, capacity benefit margin, and transmission reserve margin, because the revised standards require the development and documentation of Regional methodologies for these transfer capabilities and margins, which all transmission providers in their respective Regions are to use in calculating these factors. Having standardized Regional methodologies for total transfer capability, available transfer capability, capacity benefit margin, and transmission reserve margin reduces what had been a multiplicity of company-specific methods for these calculations to at most ten. Further, the revised standards require the posting, update, and periodic review of total transfer capability, available transfer capability, capacity benefit margin, and transmission reserve margin calculations and their resulting values to ensure that transmission providers comply with the Regional methodologies and that the methodologies and resulting values are made available to transmission users in the electricity markets. In addition, all of the Regional methodologies are required to address and meet a specific list of requirements or measurements, significantly reducing the opportunity for unnecessary Regional differences.

These standards, in general, are moving the industry toward more uniform available transfer capability and capacity benefit margin determinations. The disclosure requirements in the standards go a long way toward eliminating the misunderstandings that surround the determination of these values.

At the time the Market Interface Committee approved these revised standards, it expressed concern about the lack of complete standardization and urged that the issue be given a high priority for further efforts through NERC's new Organization Standards development process. This concern was also raised at the NERC's Stakeholders Committee. NERC will report to FERC on the development of any such new or revised capacity benefit margin and related transfer standards.

NERC requests that all correspondence and service of pleadings in this matter be sent to:

David N. Cook
North American Electric Reliability Council
116-390 Village Blvd.
Princeton, New Jersey 08540-5731
(609) 452-8060
david.cook@nerc.net

NORTH AMERICAN
ELECTRIC RELIABILITY COUNCIL

By:
David N. Cook
General Counsel

CERTIFICATE OF SERVICE

I certify that I mailed a copy of this pleading to each person on the service list for Docket No. EL99-46-000.

____

Attachment 1

PHASE IIB - NERC PLANNING STANDARDS, MEASUREMENTS, AND COMPLIANCE TEMPLATES ON TRANSFER CAPABILITY (SECTION I.E.1) (TOTAL (TTC) AND AVAILABLE (ATC) TRANSFER CAPABILITIES)

North American Electric Reliability Council

NERC Board of Trustees
February 20, 2002

Introduction — Total and Available Transfer Capabilities

A competitive electricity market is dependent on the availability of transmission services. The availability of these services must be based on the physical and electrical characteristics and capabilities of the interconnected transmission networks as reliably planned and operated under the **NERC Planning Standards**, the NERC Operating Policies, and applicable Regional, subregional, power pool, and individual system criteria.

The Total Transfer Capability (TTC) and the Available Transfer Capability (ATC) for particular directions must be available to the market participants. These transfer capabilities are generally calculated through computer simulations of the interconnected transmission systems under a specific set of system conditions.

TTC and ATC values must balance both technical and commercial issues. The definitions of the key TTC and ATC transfer capability terms that bridge the technical characteristics of interconnected transmission system performance and the commercial requirements associated with transmission service requests are as follows:

- The Total Transfer Capability (TTC) is the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions.

- Available Transfer Capability (ATC) is a measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as TTC less existing transmission commitments (including retail customer service), less a capacity benefit margin (CBM), less a transmission reliability margin (TRM). (The transfer capability margins — CBM and TRM — are defined under section I.E.2 of the Planning Standards document.)

  ATC is expressed as:

  ATC = TTC – Existing Transmission Commitments (includes retail customer service) – CBM – TRM

  Depending on the methodology used, either ATC or TTC may be calculated first.

TTC and ATC values are projected values. They are intended to indicate the available transfer capabilities of the interconnected transmission network.

Standards

S1. Each Region shall develop a methodology for calculating Total Transfer Capability (TTC) and Available Transfer Capability (ATC) that shall comply with the above NERC definitions for TTC and ATC, the NERC Planning Standards, and applicable Regional criteria.

Each Regional TTC and ATC methodology and the resulting TTC and ATC values shall be available to transmission users in the electricity market.

Measurements

M1. Each Region, in conjunction with its members, shall develop and document a Regional TTC and ATC methodology. Certain systems that are not required to post ATC values are exempt from this Standard.

This Regional methodology shall be available to NERC, the Regions, and the transmission users in the electricity market. (S1)

Each Region's TTC and ATC methodology shall (S1):

a) Include a narrative explaining how TTC and ATC values are determined.
b) Account for how the reservations and schedules for firm (non-recallable) and non-firm (recallable) transfers, both within and outside the transmission provider's system, are included.
c) Account for the ultimate points of power injection (sources) and power extraction (sinks) in TTC and ATC calculations.
d) 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.)
e) Require that TTC and ATC values and postings within the current week be determined at least once per day, that daily TTC and ATC values and postings for day 8 through the first month be determined at least once per week, and that monthly TTC and ATC values and postings for months 2 through 13 be determined at least once per month.
f) Indicate the treatment and level of customer demands, including interruptible demands.
g) Specify how system conditions, limiting facilities, contingencies, transmission reservations, energy schedules, and other data needed by transmission providers for the calculation of TTC and ATC values are shared and used within the Region and with neighboring interconnected

electric systems, including adjacent systems, subregions, and Regions. In addition, specify how this information is to be used to determine TTC and ATC values. If some data is not used, provide an explanation.

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

i) Describe the Region's practice on the netting of transmission reservations for purposes of TTC and ATC determination.

Each Regional TTC and ATC methodology shall address each of the items listed above and shall explain its use in determining TTC and ATC values.

The most recent version of the documentation of each Region's TTC and ATC methodology shall be available on a web site accessible by NERC, the Regions, and the transmission users in the electricity market.

M2. Eliminated. Requirements included in Measurement M3.

M3. Each Region, in conjunction with its members, shall develop and implement a procedure to review periodically (at least annually) and ensure that the TTC and ATC calculations and resulting values of member transmission providers comply with the Regional TTC and ATC methodology, the NERC Planning Standards, and applicable Regional criteria. Documentation of the results of the most current Regional reviews shall be provided to NERC on request (within 30 days). (S1)

M4. Each Region, in conjunction with its members, shall develop and document a procedure on how transmission users can input their concerns or questions regarding the TTC and ATC methodology and values of the transmission 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 transmission users in the electricity market. (S1

Each Region's procedure shall specify (S1):

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.

Brief Description Documentation and content of each Regional TTC and ATC methodology.

Section
I. System Adequacy and Security
E. Transfer Capability
1. Total and Available Transfer Capabilities

Standards

S1. Each Region shall develop a methodology for calculating Total Transfer Capability (TTC) and Available Transfer Capability (ATC) that shall comply with the above NERC definitions for TTC and ATC, the NERC Planning Standards, and applicable Regional criteria.

Each Regional TTC and ATC methodology and the resulting TTC and ATC values shall be available to transmission users in the electricity market.

Measurement

M1. Each Region, in conjunction with its members, shall develop and document a Regional TTC and ATC methodology. Certain systems that are not required to post ATC values are exempt from this Standard.

This Regional methodology shall be available to NERC, the Regions, and the transmission users in the electricity market. (S1)

Each Region's TTC and ATC methodology shall (S1):

- **a) Include a narrative explaining how TTC and ATC values are determined.**
- **b) Account for how the reservations and schedules for firm (non-recallable) and non-firm (recallable) transfers, both within and outside the transmission provider's system, are included.**
- **c) Account for the ultimate points of power injection (sources) and power extraction (sinks) in TTC and ATC calculations.**
- **d) 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.)**
- **e) Require that TTC and ATC values and posting within the current week be determined at least once per day, that daily TTC and ATC values and postings for day 8 through the first month be determined at least once per week, and that monthly TTC and ATC values and postings for months 2 through 13 be determined at least once per month.**

f) Indicate the treatment and level of customer demands, including interruptible demands.

g) Specify how system conditions, limiting facilities, contingencies, transmission reservations, energy schedules, and other data needed by transmission providers for the calculation of TTC and ATC values are shared and used within the Region and with neighboring interconnected electric systems, including adjacent systems, subregions, and Regions. In addition, specify how this information is to be used to determine TTC and ATC values. If some data is not used, provide an explanation.

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

i) Describe the Region's practice on the netting of transmission reservations for purposes of TTC and ATC determination.

Each Regional TTC and ATC methodology shall address each of the items listed above and shall explain its use in determining TTC and ATC values.

The most recent version of the documentation of each Region's TTC and ATC methodology shall be available on a web site accessible by NERC, the Regions, and the transmission users in the electricity market.

Applicable to

Regions.

Items to be Measured

Development and documentation of each Region's TTC and ATC methodology and the completeness of the content of each Regional TTC and ATC methodology.

Timeframe

Available on a web site accessible by NERC, the Regions, and transmission users.

Levels of Non-Compliance

Level 1

The Region's documented TTC and ATC methodology does not address one or two of the nine requirements for such documentation as listed above under Measurement M1.

Level 2

N/A

Level 3

N/A

Level 4
The Region's documented TTC and ATC methodology does not address three or more of the nine requirements for such documentation as listed above under Measurement M1, or the Region does not have a documented TTC and ATC methodology.

Compliance Monitoring Responsibility
NERC.

Reviewer Comments on Compliance Rating

Brief Description Measurement M2 eliminated. Requirements included in Measurement M3.

Brief Description

Review of transmission provider TTC and ATC calculations and resulting values for compliance with the Regional TTC and ATC methodology.

Section

I. System Adequacy and Security
E. Transfer Capability
1. Total and Available Transfer Capabilities

Standards

S1. Each Region shall develop a methodology for calculating Total Transfer Capability (TTC) and Available Transfer Capability (ATC) that shall comply with the above NERC definitions for TTC and ATC, the NERC Planning Standards, and applicable Regional criteria.

Each Regional TTC and ATC methodology and the resulting TTC and ATC values shall be available to transmission users in the electricity market.

Measurement

M3. Each Region, in conjunction with its members, shall develop and implement a procedure to review periodically (at least annually) and ensure that the TTC and ATC calculations and resulting values of member transmission providers comply with the Regional TTC and ATC methodology, the NERC Planning Standards, and applicable Regional criteria. Documentation of the results of the most current Regional reviews shall be provided to NERC on request (within 30 days). (S1)

Applicable to

Regions.

Items to be Measured

Transmission provider TTC and ATC calculations and resulting values for compliance with the Regional TTC and ATC methodology.

Timeframe

Procedure on request (within 30 days).
Documentation of results of Regional reviews on request (within 30 days).

Levels of Non-Compliance

Level 1
N/A.

Level 2
The Region did not perform a review of all transmission providers within its Region for consistency with the Regional TTC and ATC methodology, as documented per Measurement I.E.1. S1, M1, on an annual basis.

Level 3
N/A.

Level 4
The Region does not have a procedure for performing a TTC and ATC methodology consistency review of all transmission providers within its Region, or has not performed any such reviews on an annual basis.

Compliance Monitoring Responsibility

NERC.

Reviewer Comments on Compliance Rating

Brief Description Regional procedure for input on TTC and ATC methodologies and values.

Section
I. System Adequacy and Security
E. Transfer Capability
1. Total and Available Transfer Capabilities

Standards

S1. Each Region shall develop a methodology for calculating Total Transfer Capability (TTC) and Available Transfer Capability (ATC) that shall comply with the above NERC definitions for TTC and ATC, the NERC Planning Standards, and applicable Regional criteria.

Each Regional TTC and ATC methodology and the resulting TTC and ATC values shall be available to transmission users in the electricity market.

Measurement

M4. Each Region, in conjunction with its members, shall develop and document a procedure on how transmission users can input their concerns or questions regarding the TTC and ATC methodology and values of the transmission 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 transmission users in the electricity market. (S1)

Each Region's procedure shall specify (S1):

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.

.

Applicable to
Regions.

Items to be Measured
Regional procedure for receiving and addressing transmission user concerns on the TTC and ATC methodology and TTC and ATC values of member transmission providers.

Timeframe
Procedure available on a web site accessible by the Regions, NERC, and transmission users.

Levels of Non-Compliance
Level 1
N/A.

Level 2
The Region does not have a procedure available on an accessible web site, or the procedure does not provide the information necessary to complete the submittal of a comment, have it processed by the Region, and have an answer provided as indicated in the procedure.

Level 3
N/A.

Level 4
The Region has no procedure available.

Compliance Monitoring Responsibility
NERC.

Reviewer Comments on Compliance Rating

I. System Adequacy and Security
E. Transfer Capability
1. Total and Available Transfer Capabilities

G.1 The Regional responses to transmission user concerns or questions regarding the ATC and TTC methodology and values of the transmission provider(s) should be made publicly available, possibly on a web site, for consistency and to avoid duplicative customer questions.

Attachment 2

PHASE IIB – NERC PLANNING STANDARDS,

MEASUREMENTS, AND COMPLIANCE TEMPLATES

ON

TRANSFER CAPABILITY MARGINS (SECTION I.E.2)

(Capacity Benefit Margin (CBM) and Transmission Reliability Margin (TRM))

North American Electric Reliability Council

NERC Board of Trustees
February 20, 2002

Introduction — Transfer Capability Margins

In defining the components that comprise Available Transfer Capability (ATC), two transmission transfer capability margin terms, known as Capacity Benefit Margin (CBM) and Transmission Reliability Margin (TRM), are introduced.

The definitions for CBM and TRM are:

- Capacity Benefit Margin (CBM) is 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.

- Transmission Reliability Margin (TRM) is the amount of transmission transfer capability necessary to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change.

The methodologies used to determine CBM and TRM and the resulting CBM and TRM values impact ATC and, therefore, must be available to the market participants.

Standards

S1 **Each Region shall develop a methodology for calculating Capacity Benefit Margin (CBM) that shall comply with the above NERC definition for CBM and applicable Regional criteria.**

Each Regional CBM methodology and the resulting CBM values shall be available to transmission users in the electricity market.

S2. **Each Region shall develop a methodology for calculating Transmission Reliability Margin (TRM) that shall comply with the above NERC definition for TRM and applicable Regional criteria.**

Each Regional TRM methodology and the resulting TRM values shall be available to transmission users in the electricity market.

Measurements

M1. Each Region, in conjunction with its members, shall develop and document a Regional CBM methodology. This Regional methodology shall be available to NERC, the Regions, and the transmission users in the electricity market. (S1)

Each Region’s CBM methodology shall (S1):

a) Specify that the method used by each Regional member to determine its generation reliability requirements as the basis for CBM shall be consistent with its generation planning criteria.
b) Specify the frequency of calculation of the generation reliability requirement and associated CBM values.
c) Require that generation unit outages considered in a transmission provider’s CBM calculation be restricted to those units within the transmission provider’s system.
d) 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).
e) Describe the inclusion or exclusion rationale 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.

f) Describe the inclusion or exclusion rationale for generation connected to the transmission provider's system but not obligated to serve native/network load connected to the transmission provider's system.
g) Describe the formal process and rationale for the Region to grant any variances to individual transmission providers from the Regional CBM methodology.
h) 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.
i) 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).
j) Describe the inclusion or exclusion rationale for generation reserve sharing arrangements in the CBM values.

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

The most recent version of the documentation of each Region's CBM methodology shall be available on a web site accessible by NERC, the Regions, and the transmission users in the electricity market.

M2. Eliminated. Requirements included in Measurement M3.

M3. Each Region, 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 transmission users. Documentation of the results of the most current Regional reviews shall be provided to NERC on request (within 30 days). (S1)

This Regional procedure shall:

a) Indicate the frequency under which the verification review shall be implemented.

b) Require review of the process by which CBM values are updated, and their frequency of update, to ensure that the most current CBM values are available to transmission users.
c) 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.
d) Require CBM values to be periodically updated (at least annually) and available to the Regions, NERC, and transmission users in the electricity markets.

The documentation of the Regional CBM 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 on request (within 30 days).

M4. Each transmission provider shall document and make available its procedures on the use of CBM (scheduling of electrical energy against a CBM preservation) to the Regions, NERC, and the transmission users in the electricity market.

These procedures shall:

a) Require that CBM is to be used only after the following steps have been taken (as time permits): all non-firm sales have been terminated, direct-control load management has been implemented, and customer interruptible demands have been interrupted. CBM may be used to reestablish operating reserves.
b) Require that CBM shall only be used if the LSE calling for its use is experiencing a generation deficiency and its transmission provider is also experiencing transmission constraints relative to imports of energy on its transmission system.
c) Describe the conditions under which CBM may be available as non-firm transmission service. (S1)

The transmission providers shall make their CBM use procedures available on a web site accessible by the Regions, NERC, and the transmission users in the electricity market.

M5. Each transmission provider that uses CBM shall report to the Regions, NERC, and the transmission users the use of CBM by the load-serving entities' loads on its system, except for CBM sales as non-firm transmission service. This disclosure may be after the fact. (S1)

Within 15 days after the use of CBM for emergency purposes, a transmission provider shall make available the 1) circumstances, 2) duration, and 3) amount of CBM used. This information shall be available on a web site accessible by the Regions, NERC, and the transmission users in the electricity market.

The use of CBM also shall be consistent with the transmission provider's CBM use procedures.

The scheduling of energy against a CBM preservation as non-firm transmission service need not be disclosed to comply with this Standard.

M6. Each Region, in conjunction with its members, shall develop and document a Regional TRM methodology. This Regional methodology shall be available to NERC, the Regions, and the transmission users in the electricity market. (S2)

Each Region's TRM methodology shall (S2):

a) Specify the update frequency of TRM calculations.
b) Specify how TRM values are incorporated into ATC calculations.
c) 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: aggregate load forecast error (not included in determining generation reliability requirements), load distribution error, variations in facility loadings due to balancing of generation within a control area, forecast uncertainty in transmission system topology, allowances for parallel path (loop flow) impacts, allowances for simultaneous path interactions, variations in generation dispatch, and short-term operator response (operating reserve actions not exceeding a 59-minute window).

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.

d) Describe the conditions, if any, under which TRM may be available to the market as non-firm transmission service.
e) Describe the formal process for the Region to grant any variances to individual transmission providers from the Regional TRM methodology.

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

The most recent version of the documentation of each Region's methodology shall be available on a web site accessible by NERC, the Regions, and the transmission users in the electricity market.

M7. Eliminated. Requirements included in Measurement M8.

M8. Each Region, in conjunction with its members, shall develop and implement a procedure to review the TRM calculations and values of member transmission providers to ensure that they comply with the Regional TRM methodology and are periodically updated and available to transmission users. Documentation of the results of the most current Regional reviews shall be provided to NERC on request (within 30 days). (S2**)**

This Regional procedure shall:

a) Indicate the frequency under which the verification review shall be implemented.
b) Require review of the process by which TRM values are updated, and their frequency of update, to ensure that the most current TRM values are available to transmission users.
c) Require review of the consistency of the transmission provider's TRM components with its published planning criteria. A TRM value is considered consistent with published planning criteria if the same components that comprise TRM are also addressed in the planning criteria. The methodology used to determine and apply TRM does not have to involve the same mechanics as the planning process, but the same uncertainties must be considered and any simplifying assumption explained. 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.

d) Require TRM values to be periodically updated (at least prior to each season — winter, spring, summer, and fall), as necessary, and made available to the Regions, NERC, and transmission users in the electricity market.

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 on request (within 30 days).

Brief Description Documentation and content of each Regional Capacity Benefit Margin methodology.

Section
I. System Adequacy and Security
E. Transfer Capability
2. Transfer Capability Margins

Standards

S1. Each Region shall develop a methodology for calculating Capacity Benefit Margin (CBM) that shall comply with the above NERC definition for CBM and applicable Regional criteria.

Each Regional CBM methodology and the resulting CBM values shall be available to transmission users in the electricity market.

Measurement

M1. Each Region, in conjunction with its members, shall develop and document a Regional CBM methodology. This Regional methodology shall be available to NERC, the Regions, and the transmission users in the electricity market. (S1)

Each Region's CBM methodology shall (S1):

a) Specify that the method used by each Regional member to determine its generation reliability requirements as the basis for CBM shall be consistent with its generation planning criteria.
b) Specify the frequency of calculation of the generation reliability requirement and associated CBM values.
c) Require that generation unit outages considered in a transmission provider's CBM calculation be restricted to those units within the transmission provider's system.
d) 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).
e) Describe the inclusion or exclusion rationale 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.
f) Describe the inclusion or exclusion rationale for generation connected to the transmission provider's system but not obligated to serve native/network load connected to the transmission provider's system.
g) Describe the formal process and rationale for the Region to grant any variances to individual transmission providers from the Regional CBM methodology.

h) **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.**
i) **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).**
j) **Describe the inclusion or exclusion rationale for generation reserve sharing arrangements in the CBM values.**

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

The most recent version of the documentation of each Region's CBM methodology shall be available on a web site accessible by NERC, the Regions, and the transmission users in the electricity market.

Applicable to
Regions.

Items to be Measured
Development and documentation of each Region's Capability Benefit Margin methodology and the completeness of the content of each Regional CBM methodology.

Timeframe
Available on a web site accessible by NERC, the Regions, and transmission users.

Levels of Non-Compliance
Level 1
The Region's documented CBM methodology does not address one or two of the ten requirements for such documentation as listed above under Measurement M1.

Level 2
N/A.

Level 3
N/A.

Level 4
The Region's documented CBM methodology does not address three or more of the ten requirements for such documentation as listed above under Measurement M1, or the Region does not have a documented CBM methodology.

Compliance Monitoring Responsibility
NERC.

Reviewer Comments on Compliance Rating

Brief Description

Measurement M2 was eliminated. Requirements are included in Measurement M3.

Brief Description Procedure for verifying Capacity Benefit Margin values.

Section
I. System Adequacy and Security
E. Transfer Capability
2. Transfer Capability Margins

Standard

S1. Each Region shall develop a methodology for calculating Capacity Benefit Margin (CBM) that shall comply with the above NERC definition for CBM and applicable Regional criteria.

Each Regional CBM methodology and the resulting CBM values shall be available to transmission users in the electricity market.

Measurement

M3. Each Region, 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 transmission users. Documentation of the results of the most current Regional reviews shall be provided to NERC on request (within 30 days). (S1)

This Regional procedure shall:

a) **Indicate the frequency under which the verification review shall be implemented.**
b) **Require review of the process by which CBM values are updated, and their frequency of update, to ensure that the most current CBM values are available to transmission users.**
c) **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.**
d) **Require CBM values to be periodically updated (at least annually) and available to the Regions, NERC, and transmission users in the electricity markets.**

The documentation of the Regional CBM 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 on request (within 30 days).

Applicable to
Regions.

Items to be Measured
Regional procedure and its implementation for verifying member transmission provider CBM values.

Timeframe
Procedure on request (within 30 days).
Results of procedure implementation on request (within 30 days).

Levels of Non-Compliance
Level 1
N/A.

Level 2
The Region did not perform a review of all transmission providers within its Region for consistency with the Regional CBM methodology, as documented per Measurement I.E.2 S1, M1, on an annual basis.

Level 3
N/A.

Level 4
The Region does not have a procedure for performing a CBM methodology consistency review of all transmission providers within its Region, or has not performed any such review on an annual basis.

Compliance Monitoring Responsibility
NERC.

Reviewer Comments on Compliance Rating

Brief Description Procedures for the use of Capacity Benefit Margin values.

Section
I. System Adequacy and Security
E. Transfer Capability
2. Transfer Capability Margins

Standard

S1. Each Region shall develop a methodology for calculating Capacity Benefit Margin (CBM) that shall comply with the above NERC definition for CBM and applicable Regional criteria.

Each Regional CBM methodology and the resulting CBM values shall be available to transmission users in the electricity market.

Measurement

M4. Each transmission provider shall document and make available its procedures on the use of CBM (scheduling of energy against a CBM preservation) to the Regions, NERC, and the transmission users in the electricity market.

These procedures shall (S1):

- **a) Require that CBM is to be used only after the following steps have been taken (as time permits): all non-firm sales have been terminated, direct-control load management has been implemented, and customer interruptible demands have been interrupted. CBM may be used to reestablish operating reserves.**
- **b) Require that CBM shall only be used if the LSE calling for its use is experiencing a generation deficiency and its transmission provider is also experiencing transmission constraints relative to imports of energy on its transmission system.**
- **c) Describe the conditions under which CBM may be available as non-firm transmission service. (S1)**

The transmission providers shall make their CBM use procedures available on a web site accessible by the Regions, NERC, and the transmission users in the electricity market.

Applicable to

Transmission providers.

Items to be Measured

Documentation of CBM use procedures.

Timeframe

Available on a web site accessible by the Regions, NERC, and transmission users.

Levels of Non-Compliance

Level 1
The transmission provider's CBM use procedure is available and addresses only two of the three requirements for such documentation as listed above under Measurement M4.

Level 2
N/A.

Level 3
N/A.

Level 4
The transmission provider's CBM use procedure addresses one or none of the three requirements as listed above under Measurement M4, or is not available.

Compliance Monitoring Responsibility

Regions.

Reviewer Comments on Compliance Rating

Brief Description Documentation of the use of Capacity Benefit Margin.

Section
I. System Adequacy and Security
E. Transfer Capability
2. Transfer Capability Margins

Standard

S1. Each Region shall develop a methodology for calculating Capacity Benefit Margin (CBM) that shall comply with the above NERC definition for CBM and applicable Regional criteria.

Each Regional CBM methodology and the resulting CBM values shall be available to transmission users in the electricity market.

Measurement

M5. Each transmission provider that uses CBM shall report to the Regions, NERC, and the transmission users the use of CBM by the load-serving entities' loads on its system, except for CBM sales as non-firm transmission service. This disclosure may be after the fact. (S1)

Within 15 days after the use of CBM for emergency purposes, a transmission provider shall make available the 1) circumstances, 2) duration, and 3) amount of CBM used. This information shall be available on a web site accessible by the Regions, NERC, and the transmission users in the electricity market.

The use of CBM also shall be consistent with the transmission provider's CBM use procedures.

The scheduling of energy against a CBM preservation as non-firm transmission service need not be disclosed to comply with this Standard.

Applicable to

Transmission providers.

Items to be Measured

After the fact disclosure that energy was scheduled against a CBM preservation (for purposes other than non-firm transmission sales).

Timeframe

Within 15 days of the use of CBM (excluding non-firm sales).

Levels of Non-Compliance

Level 1
N/A.

Level 2
Information pertaining to the use of CBM during an energy emergency was provided, but was not made available on a web site accessible by the Regions, NERC, and transmission users in the electricity market, or meets only two of the three requirements as listed above under Measurement M5.

Level 3
N/A.

Level 4
After the use of CBM (excluding non-firm sales), information pertaining to the use of CBM was provided but meets one or none of the three requirements as listed above under Measurement M5, or no information was provided.

Compliance Monitoring Responsibility

Regions.

Reviewer Comments on Compliance Rating

Brief Description Documentation and content of each Regional Transmission Reliability Margin methodology.

Section
I. System Adequacy and Security
E. Transfer Capability
2. Transfer Capability Margins

Standard

S2. Each Region shall develop a methodology for calculating Transmission Reliability Margin (TRM) that shall comply with the above NERC definition for TRM and applicable Regional criteria.

Each Regional TRM methodology and the resulting TRM values shall be available to transmission users in the electricity market.

Measurement

M6. Each Region, in conjunction with its members, shall develop and document a Regional TRM methodology. This Regional methodology shall be available to NERC, the Regions, and the transmission users in the electricity market. (S2)

Each Region's TRM methodology shall (S2):

a) Specify the update frequency of TRM calculations.
b) Specify how TRM values are incorporated into ATC calculations.
c) 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: aggregate load forecast error (not included in determining generation reliability requirements), load distribution error, variations in facility loadings due to balancing of generation within a control area, forecast uncertainty in transmission system topology, allowances for parallel path (loop flow) impacts, allowances for simultaneous path interactions, variations in generation dispatch, and short-term operator response (operating reserve actions not exceeding a 59-minute window).

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.

d) Describe the conditions, if any, under which TRM may be available to the market as non-firm transmission service.
e) Describe the formal process for the Region to grant any variances to individual transmission providers from the Regional TRM methodology.

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

The most recent version of the documentation of each Region's TRM methodology shall be available on a web site accessible by NERC, the Regions, and the transmission users in the electricity market.

Applicable to
Regions.

Items to be Measured
Development and documentation of each Re gion's Transmission Reliability Margin methodology and the completeness of the content of each Regional TRM methodology.

Timeframe
Available on a web site accessible by NERC, the Regions, and transmission users.

Levels of Non-Compliance
Level 1
The Region's document TRM methodology does not address one of the five requirements for each documentation as listed above under Measurement M6.

Level 2
N/A.

Level 3
N/A.

Level 4
The Region's documented TRM methodology does not address two or more of the five requirements for such documentation as listed above under Measurement M6, or the Region does not have a documented TRM methodology.

Compliance Monitoring Responsibility
NERC.

Reviewer Comments on Compliance Rating

Brief Description (Measurement M7 was eliminated. Requirements included in Measurement M8.)

Brief Description Procedure for verifying Transmission Reliability Margin values.

Section
I. System Adequacy and Security
E. Transfer Capability
2. Transfer Capability Margins

Standard

S2. Each Region shall develop a methodology for calculating Transmission Reliability Margin (TRM) that shall comply with the above NERC definition for TRM and applicable Regional criteria.

Each Regional TRM methodology and the resulting TRM values shall be available to transmission users in the electricity market.

Measurement

M8. Each Region, in conjunction with its members, shall develop and implement a procedure to review the TRM calculations and values of member transmission providers to ensure that they comply with the Regional TRM methodology and are periodically updated and available to transmission users. Documentation of the results of the most current Regional reviews shall be provided to NERC on request (within 30 days). (S2)

This Regional procedure shall:

a) Indicate the frequency under which the verification review shall be implemented.

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

c) Require review of the consistency of the transmission provider's TRM components with its published planning criteria. A TRM value is considered consistent with published planning criteria if the same components that comprise TRM are also addressed in the planning criteria. The methodology used to determine and apply TRM does not have to involve the same mechanics as the planning process, but the same uncertainties must be considered and any simplifying assumption explained. 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.

d) Require TRM values to be periodically updated (at least prior to each season ¾ winter, spring, summer, and fall), as necessary, and made available to the Regions, NERC, and transmission users in the electricity market.

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 on request (within 30 days).

Applicable to
Regions.

Items to be Measured
Regional procedure and its implementation for verifying member transmission provider TRM values.

Timeframe
Procedure on request (within 30 days).
Results of procedure implementation on request (within 30 days).

Levels of Non-Compliance

Level 1
N/A.

Level 2
The Region did not perform a review of all transmission providers within its Region for consistency with the Regional TRM methodology, as documented per Measurement I.E.2 S2, M8, on an annual basis.

Level 3
N/A.

Level 4
The Region does not have a procedure for performing a TRM methodology consistency review of all transmission providers in its Region, or has not performed any such reviews on an annual basis.

Compliance Monitoring Responsibility
NERC.

Reviewer Comments on Compliance Rating