NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

ATCT Standards Drafting Team Meeting

January 11, 2007 – January 12, 2007
Houston, Texas

Draft Minutes

Administration

Chairman Larry Middleton led the welcome and introductions. Bill Lohrman reviewed the NERC Antitrust Compliance Guidelines Chairman Middleton reviewed the agenda and objectives of the meeting.

Attendance

Larry Middleton	Midwest ISO	Jim Eckelkamp	Progress Energy
Ross Kovacs	Georgia Transmission Corporation	Ron Carlson	Southern Company
Abbey Nulph	Bonneville Power Administration	Chuck Falls	Salt River Project
Dennis Harrison	Prague Power, LLC	Narinder Saini	Entergy
Nate Schweighart	TVA	Laura Lee	Duke
DuShaune Carter	Southern Company	Daryn Barker	E.ON US
Matt Schull	North Carolina Municipal Power Agency	Ray Kershaw	ITC Transmission
Kiko Barredo	Florida Power and Light	E. Nick Henery	APPA
DeDe Kirby	NAESB	Jerry Smith	Arizona Public Service
Shannon Black	SMUD		
Via conference call:			
Don Williams	PJM	Sueyen McMahon	LADWP
J.T. Wood	Southern Company	Cheryl Mendrala	New York ISO
Barbara Rehman	BPA	Sedina Eric	FERC

MOD-001-1

Chairman Middleton introduced Ed Dobrowolski, NERC Standards Development Coordinator, who reviewed various suggested modifications to the drafting team's draft of MOD-001-1. As a result of the suggestions, the team made some changes to the proposed definitions. The drafting team will work with Bill Lohrman to make some of the other suggested changes. The drafting team reviewed the comment that although TFC is linked to AFC in the draft proposed MOD-001-1; TTC is not similarly mentioned with ATC. The drafting team agreed that TFC should be removed and taken up in the revision of the FAC standards.

After completing the review of the suggested changes, Chairman Middleton discussed possible dates for posting the proposed MOD-001-1, perhaps on February 1st or February 15th. Once the comments are received and reviewed, the drafting team would like to schedule a joint meeting to review the comments with the Business Practices Subcommittee of NAESB[1].

The drafting team then discussed whether transmission service providers (TSPs) can use more than one methodology vs. having to select one methodology. Issues are (1) some systems are operated using a hybrid of rated system path and flowgate, and (2) seams issues that are introduced. The drafting team agreed to take this up on the comment form when MOD-001-1 is posted for comment, and added a question to the comment form (**Exhibit A**) to poll industry on the adequacy of choosing only one method.

The drafting team also agreed to revise Requirement R1 to remove wording that is repeated in R4 that requires that TSPs must use the selected methodology.

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[1] North American Energy Standards Board

Transmission Reserve Margin (TRM)

Chairman Middleton then introduced Nate Schweighart's draft TRM strawman document (**Exhibit B**). Mr. Schweighart then summarized the draft and reviewed the requirements. The drafting team has extensive discussion regarding the different percentage ranges that he specified in the draft. Some members of the team feel that there should be alternative methods of calculating TRM. Another method discussed is modeling a unit offline that is critical to the study interface. Some members also expressed concern that TRM is too large when expressed as a percentage when combined with the OTDF, and others feel TRM would be too large by modeling the critical unit offline. Other concerns mentioned the horizon being calculated. Perhaps the TRM is large in the longer uncertain timeframe and is reduced as the nearer timeframe becomes more certain. Further discussion covered the different types of uncertainties that TRM is meant to cover. Mr. Lohrman reviewed with the group the NERC White Paper from 1999 on TRM (**Exhibit C**), which also described two different TRM methods. Mr. Schweighart suggested that either the team agrees to use his strawman as a starting point, or someone else present to the group an alternative strawman. The team agreed that Mr. Schweighart's draft should be the starting point, and Ron Carlsen proposed to modify Nate's draft for the next meeting. A path methodology will be added.

The drafting team was assigned to begin developing questions for the comment form for the future TRM MOD posting. The drafting team was also asked to review MOD-009 for any requirements that might be transferred to MOD-008 prior to recommending deletion of MOD-009.

Some members of the team volunteered to share other TRM methodologies that had not been specifically discussed. The SERC TRM methodology will be distributed. The FRCC methodology (**Exhibit D**) is attached to these meeting minutes. Chairman Middleton also requested that the team share CBM methodologies so that the team could begin discussions of a strawman at the next meeting and a team member could be assigned to draft a proposed MOD standard.

Joint NERC NAESB Considerations

Working with NAESB team members Kathy York and J.T. Wood, the drafting team then addressed some NAESB comments regarding previously removed requirements in the MOD 001-1 draft and confirmed that some timing issues are to be handled in the companion business practice that is be developed by NAESB.

Existing Transmission Commitments (ETC)

Nick Henery suggested that a team member also volunteer to begin a proposed draft for ETC. Chairman Middleton suggested that the team begin considering a list of ETC considerations and issues for the next meeting. Shannon Black agreed to develop a strawman of those issues. Jerry Smith provided a copy of the WECC ATC and ETC requirements (**Exhibit E**).

Next Steps

The drafting team agreed to send to NAESB for informal comment a recommendation to delete MOD-002, since it is comprised primarily of compliance elements that will be contained in the new MOD-001-1. The team also agreed to send to NAESB for informal comment proposed revisions to revisions MOD-003-1.

The drafting team agreed to consideration modifications to FAC-12 and FAC-13 during its February 2007 meeting.

During the San Diego meeting the team will develop criteria for developing a CBM standard. Chairman Middleton volunteered to begin the draft.

Future meeting logistics were discussed, confirming that the San Diego meeting will still be noon to noon on January 22-23, 2007 and that the Tampa meeting will be two full days on February 7-8, 2007.

There being no further business, the meeting was adjourned.

Exhibit A

Please use this form to submit comments on the first draft of the ATC/TFC/AFC Methodology Documentation Standard (MOD-001-1 ATC, TFC, and AFC Calculation Methodologies). Comments must be submitted by T.B.D. You must submit the completed form by emailing it to sarcomm@nerc.com with the words "ATC/AFC Methodology" in the subject line. If you have questions please contact Bill Lohrman at wwlohrman@praguepower.com or 908-630-0289.

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ALL DATA ON THIS FORM WILL BE TRANSFERRED AUTOMATICALLY TO A DATABASE.

DO: **Do** enter text only, with no formatting or styles added.

Do use punctuation and capitalization as needed (except quotations).

Do use more than one form if responses do not fit in the spaces provided.

Do submit any formatted text or markups in a separate WORD file.

DO NOT: **Do not** insert tabs or paragraph returns in any data field.

Do not use numbering or bullets in any data field.

Do not use quotation marks in any data field.

Do not submit a response in an unprotected copy of this form.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT** ☐ **FRCC** ☐ **MRO** ☐ **NPCC** ☐ **RFC** ☐ **SERC** ☐ **SPP** ☐ **WECC** ☐ **NA – Not Applicable**	☐	1 — Transmission Owners
	☐	2 — RTOs, ISOs, Regional Reliability Councils
	☐	3 — Load-serving Entities
	☐	4 — Transmission-dependent Utilities
	☐	5 — Electric Generators
	☐	6 — Electricity Brokers, Aggregators, and Marketers
	☐	7 — Large Electricity End Users
	☐	8 — Small Electricity End Users
	☐	9 — Federal, State, Provincial Regulatory or other Government Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on the prior page.

Background Information

The Long-Term AFC/ATC Task Force (LTATF) was formed to develop specific recommendations for the calculation and coordination of AFC[1]/ATC[2] with the goal of increasing market liquidity and enhancing grid reliability. The task force's work was coordinated with NAESB[3] to separate business practices from reliability concerns. The LTATF evaluated the results of the short-term recommendations in the Alliant West area for summer 2004[4], and used this evaluation when considering whether to recommend the Alliant West short-term recommendations continue. The work resulted in the formation of a SAR[5] Drafting Team who formed recommendations that are the basis for the formation of a Standard Drafting Team.

In developing their recommendations the NERC LTATF considered the calculation for AFC/ATC, communication and coordination of AFC/ATC, and consistency between transmission planning and AFC/ATC calculations. A final LTATF report[6] was presented to the Standing Committees in March 2005. The task force used the report and recommendations to develop proposed standards for AFC/TFC[7]/ATC/TTC[8] and CBM/TRM. The proposed "MOD-001-1 Documentation of ATC and AFC Calculation" Standard is the culmination of the work of the NERC LTATF and Standard Drafting Team and is the subject matter for this Comment Form.

The proposed standard labeled MOD-001-1 outlines requirements for the calculation of ATC and AFC, but does not provide requirements for the calculation of TFC or TTC. The proposed standard may reference NERC Standard(s) FAC-012 and/or FAC-013 as the source for the requirements for calculation of TTC and/or TFC. Currently FAC-012 identifies requirements for the calculation of inter-regional and intra-regional Transfer Capabilities (TC). The term TTC is not mentioned in FAC-012, as described in the FERC NOPR[10]. The drafting team has put a placeholder for TFC requirements in the proposed MOD-001-1 standard pending the receipt of industry comments on the appropriate standard in which to place TFC.

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A distinct definition for the TC and TTC terms appears in the NERC *Glossary of Terms Used in Reliability Standards*[11]. The members of the drafting team are proposing that they are basically the same quantity and should be covered in a single standard in FAC-012 . Consequently, the draft version of MOD-001-1 does not contain calculation requirements for TTC. The drafting team is seeking input from the industry on this question (see Comment Form questions 9 and 10). The comment form includes questions asking whether the values for TC and TTC should be considered the same value. The questions in the comment form also ask for feedback regarding the appropriate standard in which to determine TTC and TFC (see Comment Form question 11).

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1 AFC = Available Flowgate Capability
2 ATC = Available Transfer Capability
3 NAESB = North American Energy Standards Board
4 ftp://www.nerc.com/pub/sys/all_updl/docs/pubs/AWTTF_Final_Report_032604.pdf
5 SAR = Standards Authorization Request
6 ftp://www.nerc.com/pub/sys/all_updl/mc/ltatf/LTATF_Final_Report_Revised.pdf
7 TFC = Total Flowgate Capability
8 TTC = Total Transfer Capability
10 http://www.ferc.gov/whats-new/comm-meet/051806/E-1.pdf
11 ftp://www.nerc.com/pub/sys/all_updl/standards/rs/Glossary_02May06.pdf

If the calculation of AFC and ATC are ultimately dependent upon values derived in the FAC-012 and/or the FAC-013 standard(s), the drafting team will revise FAC-012 and/or FAC-013 as necessary prior to balloting MOD-001-1 so that industry will know how those precursor values will be developed. A partial list of these precursor values could include:

- Semi-annual summer and winter TTC values
- Assumptions used for modeling generation dispatch
- Transmission and generation outage schedules
- Power flow models
- Load forecasts
- Path definitions and facility ratings
- Algorithms

Clarification of Capacity Benefit Margin and Transmission Reserve Margin will be subsequently addressed by the drafting team in proposed revisions to the respective standards.

The Standards Committee and Standard Drafting Team (ATCTDT) would like to receive industry comment on the proposed standard.

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You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Is the definition for ETC contained in this standard sufficient for the industry to calculate the ETC in a consistent and reliable manner? If not, please explain.

   ☐ Yes

   ☐ No

   Comments:

2. Should the definition for Transmission Service Request in this proposed standard be expanded or changed? Please explain your answer.

   ☐ Yes

   ☐ No

   Comments:

3. Should the drafting team definition for Flowgate be used to replace the Flowgate definition in the NERC *Glossary of Terms Used in Reliability Standards*[12]? Please explain your answer.

   ☐ Yes

   ☐ No

   Comments:

4. Do you agree with the remaining definition of terms used in the proposed standard? If not, please explain which terms need refinement and how.

   ☐ Yes

   ☐ No

   Comments:

5. Does the proposed standard include the correct Reliability Functions in the applicability section of the proposed standard? If not, please explain which functions need to be added or deleted and why.

   ☐ Yes

   ☐ No

   Comments:

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12 ftp://www.nerc.com/pub/sys/all_updl/standards/rs/Glossary_02May06.pdf

6. The standard drafting team has identified three methodologies in which the ATC and AFC are calculated (Rated System Path - ATC, Network Response - ATC and Network Response - AFC, methodologies). In developing this standard has the standard drafting team adequately addressed these methodologies? Please explain if you feel the team has not adequately addressed these methodologies within the proposed standard.

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☐ Yes

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7. The standard drafting team has identified three methodologies in which the ATC and AFC are calculated (Rated System Path - ATC, Network Response - ATC and Network Response - AFC, methodologies). Should the drafting team consider other methodologies? Please explain.

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☐ Yes

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8. The standard drafting team has identified that the Transmission Service Provider shall choose only one of the three methodologies for the Transmission Service Provider's entire system in which the ATC and AFC are calculated (Rated System Path - ATC, Network Response - ATC and Network Response - AFC, methodologies). If chosing just one of these methods is not sufficient for your system, please explain why.

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☐ Yes

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9. Do you agree with the proposed requirements included in the proposed standard? If not please explain with which requirements you do not agree and why.

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10. Does the proposed standard sufficiently address the reliability concerns expressed in the NERC LTATF Report[13] or the FERC NOPR[14]? If not, then please explain.

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☐ Yes

☐ No

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[13] ftp://www.nerc.com/pub/sys/all_updl/mc/ltatf/LTATF_Final_Report_Revised.pdf

[14] http://www.ferc.gov/whats-new/comm-meet/051806/E-1.pdf

11. Should the proposed standard include further standardization for the components of the calculation of ATC or AFC (i.e., should the proposed standard be more prescriptive regarding the consistency and standardization of determining TTC, TFC, ETC, TRM, and CBM)? If so, please explain.

☐ Yes

☐ No

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12. If it is determined that additional requirements and measures are needed for the calculation of ETC, should these requirements and measures for the calculation of ETC be contained within this standard, or should a new standard strictly for ETC be written? If so please explain.

☐ Yes

☐ No

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13. Do you agree that Total Transfer Capability (TTC) referenced in the MOD standards and Transfer Capability (TC) references in the FAC-012-1 and/or FAC-013-1 standards are the same and should be treated as such in developing this standard? Please explain your answer.

☐ Yes

☐ No

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14. If you agree in question 11 that TTC and TC represent the same values, should MOD-001-1 address the Total Transfer Capability (TTC) methodology and documentation, as opposed to having the TTC methodology addressed by revising the existing Facility Rating FAC-012-1 and/or FAC-013-1 standards as proposed by FERC NOPR[15]? Please explain your answer.

☐ Yes

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15. If you do not agree in question 11 that TTC and TC represent the same values, how should the drafting team address the similarity between Transfer Capability (TC) and Total Transfer Capability (TTC) methodology and documentation? Please explain your answer.

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[15] http://www.ferc.gov/whats-new/comm-meet/051806/E-1.pdf

16. As mentioned in the introduction, the drafting team has deferred development of requirements for the calculation of Total Flowgate Capability (TFC) pending industry comments. The drafting team would like to know whether the industry believes that MOD-001-1 needs to address TFC methodology and documentation as opposed to having the TFC methodology addressed by revising the existing Facility Rating FAC-012-1 and/or FAC-013-1 standards? Please explain your answer.

☐ Yes

☐ No

Comments:

17. Is the requirement in this proposed standard to specify the ultimate source and sink necessary for the ATC methodologies (see requirements R1.2.3 and R1.4.4)? Please explain your answer.

☐ Yes

☐ No

Comments:

18. Would the provision of a link to the location of a TSP's data be sufficient in satisfying the requirement(s) to exchange data for this proposed standard? Please explain.

☐ Yes

☐ No

Comments:

19. When calculating monthly, daily, weekly, and hourly ATC and/or AFC values, what planning horizon(s) should be used for the inclusion of CBM in the calculation of monthly, daily, and hourly ATC and/or AFC, and which reliability function(s) should make the CBM calculations? Please explain.

Comments:

20. When calculating monthly, daily, and hourly ATC and/or AFC values, what planning horizon(s) should be used for the inclusion of TRM in the calculation of monthly, daily, and hourly ATC and/or AFC, and which reliability function(s) should make the TRM calculations? Please explain.

Comments:

21. Should NERC work with NAESB to determine whether updates to ETC and ATC values should be posted after the transmission request is accepted or after it has been confirmed? Please explain.

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22. In order to maintain consistency with planning requirements, should NERC work with NAESB to establish a business practice to monitor Load Serving Entities (LSE), Generation Operators, or Purchasing/Selling Entities that might reserve transmission service in multiple directions in excess of either the LSE load or the capacity of the generator? If so, please explain.

☐ Yes

☐ No

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23. Does the proposed standard address the goals of the related SAR[16] and the LTATF report[17] to improve communication, coordination, standardization, and transparency? If not, please explain.

☐ Yes

☐ No

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24. Do you agree with the Risk Factors[18] assigned to the Requirements in this proposed standard? If not which do you disagree with and why (please specify if the Risk Factor is too high or too low)?

☐ Yes

☐ No

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25. Do you agree with the Violation Severity Levels[19] in this proposed standard? If not, with which do you disagree and why (please specify)?

☐ Yes

☐ No

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26. Should any of the data elements required to be exchanged among Transmission Service Providers in this proposed standard be provided to any other functional entities? Please explain your answer.

☐ Yes

☐ No

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[16] ftp://www.nerc.com/pub/sys/all_updl/standards/sar/SAR_ATC-TTC_R2_15Feb06.pdf
[17] ftp://www.nerc.com/pub/sys/all_updl/mc/ltatf/LTATF_Final_Report_Revised.pdf
[18] Please see APPENDIX attached to this comment form
[19] Please see APPENDIX attached to this comment form

Comments:

27. Is the frequency of providing data specified in this proposed standard appropriate? Please explain your answer.

☐ Yes

☐ No

Comments:

28. Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

Comments:

29. Do you agree with the Measures listed in the proposed standard? If not, please explain your answer.

☐ Yes

☐ No

Comments:

30. Do you have other comments on the proposed standard?

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☐ Yes ¶
☐ No ¶
Comments:¶
¶
<#>Should the drafting team working definition for Flowgate be used to replace the Flowgate definition in the NERC *Glossary of Terms Used in Reliability Standards*[20]? Please explain your answer.¶
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APPENDIX

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Violation Risk Factors (Risk Factor)

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures;

or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures;

or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. A requirement that is administrative in nature;

or a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

Violation Severity Levels

The drafting team should indicate a set of violation severity levels that can be applied for the requirements within a standard. (‘Violation severity levels’ replace existing ‘levels of non-compliance.’) The violation severity levels may be applied for each requirement or combined to cover multiple requirements, as long as it is clear which requirements are included.

- **Lower: mostly compliant with minor exceptions** — The responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more minor details. Equivalent score: 95% to 99% compliant.

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- **Moderate: mostly compliant with significant exceptions** — The responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more significant elements. Equivalent score: 85% to 94% compliant.
- **High: marginal performance or results** — The responsible entity has only partially achieved the reliability objective of the requirement and is missing one or more significant elements. Equivalent score: 70% to 84% compliant.
- **Severe: poor performance or results** — The responsible entity has failed to meet the reliability objective of the requirement. Equivalent score: less than 70% compliant.

Exhibit B

A. Introduction

1. **Title:** **Calculation and Documentation Methodology for Transmission Reliability Margin**

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

3. **Purpose:** To promote the consistent use of a calculation and documentation methodology for each Transmission Service Provider's Transmission Reliability Margin

4. **Applicability:**

   4.1. Transmission Service Provider

5. **Effective Date:**

B. Requirements

R1. Transmission Reliability Margin consists of two components, the uncertainty component and the generation reserve sharing component. Each Transmission Service Provider must define, within the limits of the standard, and document an amount set aside to make up each component of the Transmission Reliability Margin.

R1.1. Each Transmission Service Provider will define a percentage of transmission element facility ratings (of facilities used as limits in ATC calculations) as the uncertainty component of the Transmission Reliability Margin. Each element or groups of elements may have different percentages set aside as long as it is clear in the documentation what percentage is set aside for each element or group of elements.

R1.2.1. If the percentage defined for a specific element or group of elements, used as limits in ATC calculations, is between 0% and 2%, then the Transmission Service Provider must provide an explanation in its documentation why that percentage is used and historical data that reinforces the explanation.

R1.2.2. If the percentage defined for a specific element or group of elements, used as limits in ATC calculations, is greater than 2% and less than 5%, then the Transmission Service Provider must provide an explanation in its documentation why that percentage is used and historical data that reinforces the explanation..

R1.2.3. If a percentage defined for a specific transmission element or group of elements is greater than 5% the Transmission Service Provider must provide in its documentation an explanation of why the higher percentage is need and historical data that reinforces the explanation. The historical data may include, but is not limited to: load forecast error, load distribution error, loop flow impacts, variations in generation dispatch. A study of the transmission system may be substituted for the historical data if large simultaneous path interactions are the reason a larger amount is used.

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

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

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R1.2.1. The Transmission Service Provider will include in its documentation, the methodology describing how the amounts are defined and a copy of the study in which the current amounts are calculated.

R1.2.2. If the amount is zero or the Transmission Service Provider does not participate in generation reserve sharing, all that is needed is a statement reflecting this in the documentation.

R2. The Transmission Service Provider will, at a minimum, review its Transmission Reliability Margin quarterly and update any required studies or explanations required in its documentation at that time.

R3. The Transmission Service Provider will document the amount of Transmission Reliability Margin that will be subtracted from the Total Transfer Capacity (TTC) on each interface. This amount is the values previously defined in R1.2, if the Transmission Service Provider chose to set a part of Transmission Reliability Margin aside as interface transfer capability.

R3.1. The Transmission Service Provider will document the amount of Transmission Reliability Margin that will be made available to the market as Non-Firm Transmission Service.

R4. The Transmission Service Provider will make available its most recent version of its Transmission Reliability Margin documentation on their OASIS website.

C. Measures

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

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

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: NERC.

1.2. Compliance Monitoring Period and Reset Timeframe

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

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: The Regional Reliability Organization's documented TRM methodology does not address one of the five items required for documentation under Reliability Standard MOD-008-0_R1.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

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Deleted: <#>Each Regional Reliability Organization, in conjunction with its members, shall develop and document a Regional TRM methodology. The Region's TRM methodology shall specify or describe each of the following five items, and shall explain its use, if any, in determining TRM values. Other items that are Region-specific or that are considered in each respective Regional methodology shall also be explained along with their use in determining TRM values.¶
<#>Specify the update frequency of TRM calculations.¶
<#>Specify how TRM values are incorporated into Available Transfer Capability calculations.¶
<#>Specify the uncertainties accounted for in TRM and the methods used to determine their impacts on the TRM values. Any component of uncertainty, other than those identified in MOD-008-0_R1.3.1 through MOD-008-0_R1.3.7, shall benefit the interconnected transmission systems as a whole before they shall be permitted to be included in TRM calculations. The components of uncertainty identified in MOD-008-0_R1.3.1 through MOD-008-0_R1.3.7, if applied, shall be accounted for solely in TRM and not CBM. ¶
<#>Aggregate Load forecast error (not included in determining generation reliability requirements). ¶
<#>Load distribution error.¶
<#>Variations in facility Loadings due to balancing of generation within a Balancing Authority Area.¶
<#>Forecast uncertainty in transmission system topology.¶
<#>Allowances for parallel path (... [1]

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2.4. Level 4: The Regional Reliability Organization's documented TRM methodology does not address two or more of the five items required for documentation under Reliability Standard MOD-008-0_R1.

Or

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

E. Regional Differences

1. None identified.

Version History

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

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Specify the update frequency of TRM calculations.

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

Load distribution error.

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

Forecast uncertainty in transmission system topology.

Allowances for parallel path (loop flow) impacts.

Allowances for simultaneous path interactions.

Variations in generation dispatch.

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

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

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

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

Exhibit C

Transmission Capability Margins and Their Use in ATC Determination

White Paper

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

June 17, 1999

Table of Contents

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 thersfore, 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 decease) 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 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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Exhibit D

FRCC TRM Methodology (from FRCC ATC Methodology Document on OASIS)

5. TRM

Intra-Regional TRM [R1 MOD-008-0]

Each Transmission Provider individually determines the appropriate amount of TRM at each of its interfaces taking into account the facilities of other FRCC Transmission Providers by modeling, when appropriate, a generating unit off-line that is critical to that particular interface and computing the transfer capability obtained using either the most limiting contingency (line or generating unit (inertial response)) or FRCC operating reserves (ORes) scheduled in a loadflow due to the outage of the most limiting generating unit. Should there be no generating unit critical to the interface, a unit outage should be modeled, when appropriate, as ORes scheduled in a loadflow followed by single line or generator (inertial response) contingencies. The most restrictive of these transfer values is then subtracted from the TTC (with all generating units available) to arrive at the TRM. [R1.3 MOD-008-0] ORes is determined within FRCC by modeling each utility's allocated share of operating reserve requirements (for the particular unit to be modeled off-line) consistent with the latest FRCC Operating Reserve Policy. ORes is only applicable to intra-regional interfaces, and is considered a short-term operator response that ensures reliability of the Regional system. This TRM methodology explicitly accounts for uncertainties by modeling variations in generation dispatch (critical unit off-line), or Short-term Operator response (ORes scheduled), [R1.3.7, R1.3.8 MOD-008-0] and implicitly accounts for other uncertainties such as aggregate load forecast error, load distribution error, variations in facility loadings due to balancing of generation within a Balancing Authority Area, forecast uncertainty in transmission system topology, parallel impacts, or simultaneous path interactions, [R1.3.1-R1.3.6 MOD-008-0] and ensures that TRM is updated for each Daily and longer term ATC calculation. [R1.1 MOD-008-0] [R1.4 MOD-009-0]

To the extent that system conditions allow without adversely impacting reliability, TRM will be made available for transmission service on a nonfirm basis. [R1.4 MOD-008-0]

Inter-Regional TRM

The following owners (Florida Power and Light Company, Progress Energy Florida , and JEA) of the Inter-Regional interface of FRCC with SERC have developed a TRM methodology to coordinate their interface ATC postings on the Florida OASIS (FLOASIS). This TRM value represents the inertial response from SERC for the loss of a 500 MW Class generating unit in FRCC. Ninety percent of all generating units within FRCC are less than 500 MW. This TRM value provides a reasonable margin for the forced outage of generators which will affect the transfer capability of this interface as well as providing for the avoidance of frequent curtailments of firm transactions. This TRM methodology is consistent and similar to the methodology used by SERC entities in setting a TRM value on the SERC side of this interface for imports into SERC from FRCC. This methodology is also consistent with the FRCC criteria for intra-regional TRM, which allows for the sudden loss (inertial response) margin.

To the extent that system conditions allow without adversely impacting reliability, TRM will be made available for transmission service on a nonfirm basis. [R1.4 MOD-008-0]

Should a Transmission Provider, on behalf of its LSE, find that it needs special provisions for TRM that is unique, it shall send a written request for review to the Chair of the ATCWG, who shall notice the members of the ATCWG, and convene a meeting if necessary to review the request for the exception. The FRCC ATCWG shall provide the requestor with a written response documenting the request, the decision of the ATCWG, and the rationale for the decision. [R1.5 MOD-008-0]

The FRCC ATCWG shall conduct an annual review [R1.1 MOD-009-0] of the Transmission Providers' documentation and procedures for calculating TRM, including frequency of update [R1.2 MOD-009-0], and consistency with the Transmission Provider's published planning criteria [R1.3 MOD-009-0] on behalf of its respective LSE. This review shall be available on the FRCC WEB site. [R1 MOD-009-0]

FRCC CBM Methodology (from FRCC ATC Methodology Document on OASIS)

4. CBM

Each FRCC Transmission Provider makes an assessment of the CBM needed for its respective LSE's required on such transmission system, to enable access to generation from other 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 protect the LSE in times of emergency generation deficiencies. CBM may be preserved only on the Transmission Provider's (TP) system where the LSE load is located (i.e. CBM is an import quantity only). [R1.4 MOD-004-0] In determining the amount of CBM to be reserved either probabilistic or deterministic generation reliability analysis may be utilized. The computation of generation reliability requirement and associated CBM values needs to be done at least annually, in a manner consistent with its generation planning criteria. [R1.1, R1.2 MOD-004-0] The FRCC TPs currently include their total load; therefore, interruptible demands are not utilized in determining CBM values. [R1.9 MOD-004-0] It is understood that generation resources not directly connected to the TP's system but serving LSE loads are not utilized in determining CBM values, [R1.5 MOD-004-0] generation resources connected to the TP's system but not obligated to serve LSE loads are also not utilized in determining CBM values, [R1.6 MOD-004-0] and that only generation unit outages considered within a TP's system shall be utilized for determining CBM values [R1.3 MOD-004-0] unless a special provision is sought as provided for below. Should a Transmission Provider, on behalf of its LSE, find that it needs special provisions for CBM that is unique, it shall send a written request for review to the Chair of the ATCWG, who shall notice the members of the ATCWG, and convene a meeting if necessary to review the request for the exception. [R1.7 MOD-004-0] The FRCC ATCWG shall provide the requestor with a written response documenting the request, the decision of the ATCWG, and the rationale for the decision.

The appropriate amount of transmission interface capability is then reserved by the Transmission Provider for CBM on a per interface basis, ensuring that the sum of the CBM values allocated to all interfaces does not exceed that portion of the generation reliability requirement that is to be provided by outside resources [R1.8 MOD-004-0], taking into account the amount of generation available on other interconnected systems, the respective load peaking diversities of those systems, and TRM. Operating reserves may be included if appropriate in TRM and subsequently subtracted from the CBM needed. FRCC TPs do not include generation reserve sharing in CBM values. [R1.10 MOD-004-0]

Each FRCC member Transmission Provider shall document on the FLOASIS website it's procedures for calculating CBM, and at least annually update the calculated CBM value [R1.4 MOD-005-0]. The FRCC ATCWG shall conduct an annual review of the Transmission Providers documentation and procedures for calculating CBM, including frequency of update [R1.2 MOD-005-0], and consistency with the Transmission Provider's published planning criteria [R1.3 MOD-005-0] on behalf of its respective LSE. [R1.1 MOD-005-0] This review shall be scheduled after filing of the annual FRCC L&RP, and shall be available on the FRCC WEB site. [R1, R2 MOD-005-0]

Exhibit E

Determination of Available Transfer Capability Within The Western Interconnection

June 2001

Rocky Mountain Operation and Planning Group
Northwest Regional Transmission Association
Southwest Regional Transmission Association
Western Regional Transmission Association
Western Systems Coordinating Council

CONTENTS

Determination of Available Transfer Capability Within the Western Interconnection

1. Introduction

Members of the Regional Transmission Groups (RTGs) and other entities in the Western Interconnection are obligated to provide information to their members and the public regarding Available Transfer Capability (ATC) for transmission paths, in accordance with National Electric Reliability Council (NERC) and Western Systems Coordinating Council (WSCC) standards, the Regional Transmission Group (RTG) Governing Agreements, the Federal Energy Regulatory Commission (FERC) Order 888 Open Access Tariffs, and FERC Order 889. In addition, NERC and FERC are looking for additional industry development of definitive methods for determining ATC.

Transmission Providers in the Western Interconnection will determine ATC in accordance with the NERC document "Available Transfer Capability Definitions and Determination". This Western Interconnection methodology document provides more detail and specific methodology for ATC determination based on commercial practices in the Western Interconnection. The methodology builds upon the Rated System Path based method that is used for determining Total Transfer Capability (TTC) in the Western Interconnection and is intended to fully comply with all NERC, WSCC, RTG and FERC rules regarding ATC. It provides additional details, principles, and reasonableness tests upon which a broad membership consensus has been reached. The Rated System Path Methodology is described in Appendix B of the NERC Report, "Available Transfer Capability Definitions and Determinations."

The Parties to this document acknowledge that given industry restructuring the California Independent System Operator (CaISO) and other future RTOs may have different operational protocols for calculating transmission availability. The CaISO is a non-profit public benefit corporation organized under the laws of the State of California. The CaISO is responsible for the reliable operation of a grid comprising the transmission systems of Pacific Gas & Electric Company, Southern California Edison Company and San Diego Gas & Electric Company. The CaISO, pursuant to its approved Tariff by the FERC, provides open and non-discriminatory transmission access to the market participants in its Day Ahead, Hour Ahead and Real Time Markets. Under that Tariff, CaISO follows different criteria for TTC, TRM and CBM allocations.

2. Methodology and Implementation

This document describes the Western Interconnection's regional practice and methodology for the determination of ATC. It is intended to be the Western Interconnection's standard reference document for the determination of ATC. This methodology is intended to be consistent with the requirements of NERC ATC standards. The use of ATC will be governed by the Transmission Providers' tariffs developed consistent with FERC published decisions, policies and regulations. Disputes between participants will be addressed through the process provided in the tariff or through other applicable dispute resolution processes (i.e., RTG, WSCC, other).

Each Transmission Provider's ATC methodology document shall be reviewed periodically by WSCC to ensure the procedures and practices described in their documents are consistent with the Western Interconnection ATC document and NERC standards as relates to reliability of the interconnected system. This periodic review shall not include the assessment of the Transmission

Provider's implementation of its transmission services tariff but shall verify reliability standards are observed while providing transmission services.

3. Applicability

This document and the methodology herein, apply to all members of the Parties in accordance with their governing authorities**.** Individual Transmission Provider variances from this methodology will be requested by the Transmission Provider and approved by the appropriate organization (FERC, Regional Transmission Association, or WSCC).

4. Scope

This document governs only the methodology for determination of ATC and required frequency for updating ATC. The obligation of participants to post ATC on an OASIS should be in accordance with FERC Orders 888 and 889 or their successor documents.

5. Purpose

The purpose of this document is to ensure consistent implementation within the Western Interconnection of the definition and determination of ATC. For the Members of these organizations, it is intended to supplement the WRTA Governing Agreement, NRTA Governing Agreement and SWRTA Bylaws (collectively, "RTG Governing Agreements"), which broadly define ATC and outline a method for requesting transmission service.

This document builds upon and supplements the rules, definitions, principles and processes delineated in the following:

- NERC Report on Available Transfer Capability Definitions and Determination (June 1996).
- NERC Report on Transmission Transfer Capability (May 1995)
- NERC Transfer Capability Margins Standard (proposed, add issue date when finalized*)*
- WSCC Procedures for Regional Planning Project Review and Rating Transmission Facilities (original dated March 1995)
- FERC Order 888 or successor documents (Open Access Tariffs) (original dated April 1996)
- FERC Order 889 or successor documents (Open Access Same-Time Information Systems) (original dated April 1996)
- Western Regional Transmission Association Governing Agreement (January 1995)
- Northwest Regional Transmission Association Governing Agreement (February 1995)
- Southwest Regional Transmission Association Bylaws (June 1995)
- Joint Transmission Access Principles (CCPG) (December 1991)

Summaries of any information contained in any of the documents listed above are not intended to imply any deviation from the contents of those documents.

6. Determination of ATC

The process for determining ATC for each Transmission Provider in a path should be reasonable, auditable and supportable. It consists of three steps: (1) the determination of path Total Transfer Capability (TTC), (2) the allocation of TTC among Transmission Providers, and (3) the determination of each Transmission Provider's Committed Uses. A Transmission Provider's ATC is then determined by subtracting Committed Uses from allocated TTC.

ATC = TTC (allocated) - Committed Uses

Using NERC ATC terminology,

Committed Uses = TRM + Existing Transmission Commitments (including CBM)

where TRM = Transmission Reliability Margin
CBM = Capacity Benefit Margin

For information on the determination of ATC and the related operating and planning relationships, refer to the NERC document, "Available Transfer Capability - Definitions and Determination" specifically the Sections entitled Determination of Available Transfer Capability, page 15, Commercial Components of Available Transfer Capability, pages 15 to 18, and Non-Recallable (Firm) and Recallable (Non-firm) Relationships and Priorities, pages 18 to 21.

ATC shall be calculated with the following frequencies:

- Hourly ATC for the next 168 hours: Once per day
- Daily ATC for the next 30 days: Once per week
- Monthly ATC for months 2 through 13: Once per month

Transmission Providers should use the best assumptions available for all TTC and ATC calculations. Calculations for hourly ATC within the current week should take into account the load variations during the day, any partial day outages, and best estimates of probable unscheduled flow and location of operating reserves. Daily calculations will use only peak loading for the day, and have to take into acount all partial day outages. Monthly calculations will use broader based assumptions such as monthly peak, accounting for all major outages during the month, and less specific estimates of unscheduled flow and location of operating reserves.

Generally in the Western Interconnection, netting of reservations and schedules cannot be used to increase firm ATC. There is one exception to this general rule which can be implemented on a case-by-case basis when the Transmission Provider, at its sole discretion, determines that they can do so without degrading system reliability. This exception can be invoked if there is firm load on one side of the path in question and the generation resources scheduled to serve it are on the other side of the path. Firm ATC across the path in the direction from the load to the generator can be increased by the scheduled amount from the generator to the load minus an adjustment for operating reserves and back up resources. This adjustment is determined by the location of the operating reserves and back up resources that would be deployed if the original resources serving the load were lost. Each application of this exception must be carefully analyzed based upon the specific circumstances before firm netting is employed. See Appendix I for an illustration and more details.

Parties seeking ATC on constrained paths should contact the Transmission Provider who will then work with generators on the Transmission Provider's system to assess its ability to make ATC available through redispatch and the costs associated with the redispatch, consistent with the Transmission Provider's tariff. If the constraint is related to a nomogram limitation, parties may utilize applicable nomogram market mechanism procedures.

6.1 Determination of Total Transfer Capability (TTC)

TTC represents the reliability limit of a transmission path at any specified point in time. It is a variable quantity, dependent upon operating conditions in the near term and forecasted conditions in the long term. TTC shall be calculated consistent with the requirements of FERC Orders 888 and 889 and as needed to represent system conditions, but no less frequently than seasonally. TTC cannot exceed the path rating. Within the Western Interconnection, a wide area approach is used to determine TTC on a path basis using the Rated System Path method discussed in WSCC's "Procedures for Regional Planning Project Review and Rating Transmission Facilities" and NERC's "Report on Available Transfer Capability Definitions and Determination". The determination of TTC is required to conform with WSCC's "Procedures for Regional Planning Project Review and Rating Transmission Facilities" and WSCC's "Minimum Operating Reliability Criteria". Specific system operating conditions (system topology, load/generation patterns, simultaneous path loadings, and facility outages) may require that TTC or TRM be adjusted to maintain system reliability.

TTC may sometimes be better defined by a nomogram, a set of nomograms, or a series of equations than by a single number, particularly when determining TTC values for two or more parallel or interacting paths. Where the simultaneous transfer capabilities of paths are limited by the interactions between paths, the Transmission Provider should make this known on the OASIS. This may be done by posting non-simultaneous TTC and subtracting TRM, where TRM includes the difference between non-simultaneous and simultaneous limits. As an alternative to computing TRM, the Transmission Provider may post non-simultaneous TTC and describe on the OASIS the nomogram and associated curtailment conditions. In either case, Firm ATC should be based on the best estimate of the simultaneous capability of the path during the period posted.

The total net schedules on a Path are not to exceed the Path TTC.

6.2 Allocation of TTC

When multiple ownership of transmission rights exists on a path or parallel/interacting paths, it is necessary to reach agreement on the allocation of those transmission rights in order to determine and report ATC.[1] A single TTC number, appropriate for the actual or projected condition of the transmission system, will be agreed upon for the path and this TTC will then be allocated between the Transmission Providers, to yield each Transmission Provider's share of the path's TTC for the ATC posting period.

If the Transmission Providers can't come to an agreement amongst themselves, the WSCC and the RTGs in the Western Interconnection provide several dispute resolution forums through which path rating and allocation issues may be addressed.

[1] The allocation rules may address allocations for both normal conditions and system outage conditions.

6.3 Determination of Committed Uses

This section describes the principles, practices and methodology for the determination of Committed Uses[2] in terms of the NERC components of TRM, Existing Transmission Commitments and CBM.

6.3.1 Principles for Determination of Committed Uses

This document adopts an approach for addressing the determination of Committed Uses.

The key to the successful implementation of this approach is development of specific principles, guidelines and reasonableness tests that will be used by Transmission Providers in making their assumptions and determinations of Committed Uses and will provide guidance for dispute resolution proceedings.

Transmission Providers will be expected to:

- Use reasonable, "good-faith" assumptions, consistent with general principles outlined in this document

- Make those assumptions and the underlying justifications for those assumptions available, in accordance with NERC and WSCC standards, the RTA Governing Agreements, FERC Order 888 and FERC Order 889 or their successor documents.

- Justify such assumptions and results, if called upon to do so, in applicable dispute resolution forums, (i.e. FERC 888 tariff process and RTG, WSCC or other dispute resolution processes).

- Adopt assumptions which are consistent with documented and consistently applied reliability requirements, including WSCC Minimum Operating Reliability Criteria, WSCC Power Supply Design Criteria, WSCC Reliability Criteria for System Planning, and the transmission provider's documented and consistently applied internal reliability criteria.

- Apply all assumptions comparably, non-discriminatorily and reasonably. A Transmission Provider's assumptions and methodologies, taken as a whole, must be consistently applied in the treatment of all Transmission Customers in a comparable and non-discriminatory manner.

[2] Committed Uses, as described in the RTA Bylaws, are composed of (1) native load uses, (2) prudent reserves, (3) existing commitments for purchase/exchange/deliveries/sales, (4) existing commitments for transmission service and (5) other pending potential uses of transfer capability.

- Use assumptions and methodologies that facilitates market participation, provided that the outcome meets transmission system reliability requirements and does not impose uncompensated transmission services costs on the Transmission Provider.

- A Transmission Provider's assumptions and methodologies for determining ATC must be consistent with the assumptions used by the Transmission Provider in other aspects of its business (for example, system planning).

6.3.2 Determination of Transmission Reliability Margin (TRM)

TRM is the amount of transmission transfer capability necessary to provide a reasonable level of assurance that the interconnected transmission network will be secure under a broad range of uncertainties in system conditions. TRM accounts for the inherent uncertainty in system conditions and system modeling, and the need for operating flexibility to ensure reliable system operation as system conditions change.

The benefits of TRM extend over a large area and possibly over multiple providers. TRM results from uncertainties that cannot reasonably be mitigated unilaterally by a single provider. In accordance with the terms and conditions of the Transmission Provider's tariff, TRM may be sold on a non-firm basis providing that reliability of the system is not jeopardized. TRM should not be sold as firm.

Each Transmission Provider should make its TRM values and calculation methodology publicly available. The TRM requirement should be reviewed and appropriate updates made by the TPs at a minimum prior to each Operating Season.

In the Western Interconnection methodology, firm ATC reductions associated with TRM may include the following components. TRM may be set to zero.

- Transmission necessary for the activation of operating reserves
- unplanned transmission outages (for paths in which contingencies have not already been considered in establishing the path rating)
- simultaneous limitations associated with operation under a nomogram
- loading variations due to balancing of generation and load
- uncertainty in load distribution and/or load forecast [3]
- allowances for unscheduled flow

[3] Transmission Provider's allowances for load forecasts uncertainty may be part of TRM provided that: (1) the allowance is available as non-firm service on a comparable and non-discriminatory basis, (2) the allowance reduces the exposure to curtailments to all Transmission Customers with firm reservations on a prorata basis for unanticipated load, and (3) the allowance does not duplicate consideration of uncertainty within the load forecast itself.

Transmission capacity required to implement operating reserve sharing agreements for the period immediately following a contingency and before the market can respond (currently up to 59 minutes following the contingency) are included in TRM.

If the limitation on the use of TRM to 59 minutes would force a Transmission Provider to set aside unnecessary CBM on the same path as the TRM, that Transmission Provider may utilize the TRM beyond the 59 minutes. This would allow the Transmission Provider to maximize the ATC by not needlessly setting aside twice the amount of transmission (TRM and CBM) than is necessary for reliability.

TRM does not include allowances for planned outages and other known transmission conditions which should be included in the calculation of TTC. The Transmission Provider has the option of including the above described components of TRM in either the determination of TRM or TTC, but not in both.

Allowances for transmission contingencies should not be included in TRM for paths which have had an Accepted Rating established, since contingencies are already included in the determination of the Accepted Rating. A Transmission Customer with firm reservations which desires to reduce its risk of pro-rata curtailment must explicitly request a reservation of additional rights. Such rights cannot be reserved under the auspices of CBM or TRM. Where such reserved rights are not scheduled for use, the Transmission Provider is required to make such rights available to other transmission service requesters in accordance with FERC Order 888 rules or their successors.

Regarding nomogram operation, the purpose for applying TRM on paths which are governed by nomograms is to account for the uncertainty in capacity availability created by the existence of the nomogram. This is used to establish the amount of firm ATC the Transmission Provider can offer. The size of this TRM adjustment will vary based on specific circumstances. The Transmission Provider should consider such issues as the frequency which specific nomogram thresholds (such as loading levels on interacting paths, generation levels, ambient temperatures, etc.) are reached and the duration that those conditions exist when determining the TRM adjustment. In cases where an allocation of firm rights has been established between two paths related by a nomogram, the TRM reflects the difference between this firm allocation and the path's TTC. TRM set aside specifically for this nomogram adjustment should be offered as non-firm ATC.

Allowance for generation and load balancing and for uncertainty in load distribution and/or load forecast, should be determined through the use of power flow studies and/or historical operating experience. TRM should not include margin already afforded by the WSCC Reliability Criteria or otherwise accounted for in the determination of TTC.

Unscheduled flow may be handled in either of two ways, either of which is acceptable, provided that the methodology is applied consistently and non-discriminatorily:

- The path can be reserved up to its TTC, without factoring in any estimates of unscheduled flows. In such a case, when unscheduled flows materialize, accommodations and curtailments will be made consistent with the WSCC Unscheduled Flow Mitigation Plan.

- The path operator, using reasonable, auditable, supportable projections, may subtract sufficient transfer capability from TTC, as a component of TRM, to reduce the need to make curtailments associated with projected unscheduled flows.[4] This should be made available as Non-firm transfer capability in case unscheduled flow is less than anticipated.

One method of presenting TRM is to calculate it as a percentage of TTC. Uncertainties accounted for in TRM become more defined in the operating horizon as compared to the planning horizon. This is reflected in smaller TRM values in the operating time frame.

6.3.3 Determination of "Existing Transmission Commitments"

This section identifies those items to be included in the determination of "Existing Transmission Commitments".

- Reservations for Native Load Growth: Transmission Providers may reserve existing transfer capability needed for reasonably forecasted Native Load growth[5]. Transfer Capability reserved for Native Load growth must be made available for use by others until the time that it is actually needed by the Native Load.

- Where transmission service is reserved for a Network Resource which is a purchase by the Transmission Provider to serve Native Load customers, the reservation should reflect the terms of the purchase (if 50 MW may be scheduled in any hour, then 50 MW of transmission must be reserved for every hour). Where the reservation is made based on the Native Load reliability need, the Transmission Provider must determine the applicable hours of such reliability need based on its load and resource circumstances.

- Native Load Forecasts: ATC determination does not presume the existence of sanctioned forecasts by regulatory agencies, although a Transmission Provider may use such a sanction in arguing the reasonableness of its determination of Committed Uses. In making reservations for Native Load, adjustments may be made for near-term uncertainties (e.g. weather). Long-term forecasts may use both generic and contractually committed resources to meet native load requirements. Transmission Providers must use reasonable assumptions in determining Native Load requirements and make available those assumptions and the resulting conclusions, and be able to justify the reasonableness of those assumptions and the resulting conclusions, as well as their consistency with then-current FERC policies, in applicable dispute resolution proceedings.

- Approved Load Forecast: A publicly-approved load forecast or resource plan is one which has been approved, or reviewed and accepted, by a regulatory agency

[4] Note: the SWRTA Bylaws specifically permit the exclusion of transmission capacity needed to accommodate unscheduled flows, at levels consistent with the WSCC Unscheduled Flow Mitigation Plan. Making allowances for projected unscheduled flows based on assumptions that are appropriate for the time horizon of the ATC estimate would be consistent with making the best technical estimate of ATC, and would therefore be consistent with the NERC ATC report.

[5] See footnote 2.

that is independent of the Transmission Provider. If there is no regulatory-approved forecast/plan, the Transmission Provider may publish its own good-faith forecast/plan (for example, an official Loads & Resources plan). The Transmission Provider must also provide the assumptions, and the underlying justifications for those assumptions, used to develop the forecast/plan, in sufficient detail to permit interested parties to examine and challenge the reasonableness of the forecast/plan in an applicable dispute resolution forum.

Evidence supporting the contention that such a forecast/plan has been made in good faith includes a showing that the forecast/plan produced for the purposes of determining Committed Uses and ATC is consistent with the forecast/plan the Transmission Provider uses in its internal planning of other facilities or for processes distinct from those related to determination of Committed Uses. Where there are differences in the ATC methodology from the internal planning assumptions and criteria they must be explained and be subject to a finding of reasonableness in an applicable dispute resolution forum.

Long-term forecasts generally state a net out-of-area resource requirement, but may not break this requirement down by interconnection path/interface or by time-of-use period. The Transmission Provider may use his discretion to make this breakdown, provided the Transmission Provider uses good faith and provides the underlying justifications. Use of a Transmission Provider's own data, assumptions and contracts for service is probably the most reasonable solution that can be attained unless there is an RTG-approved or WSCC-approved area-wide resource database used by all parties posting ATC. The forecast should distinguish between committed and planned resource purchases.

- Ancillary Services (required as a part of Native Load service): Transfer capability should be reserved under Native Load for those ancillary services required to serve Native Load. These include transfer capability required to supply load regulation and frequency response services. Ancillary services for Operating Reserves are covered under Section 6.3.4.

- Reservations Beyond Reliability-Based Needs: A Transmission Provider may reserve ATC for the import of power which is beyond the amount reserved for reliability needs of their Native Load customers, only to the extent permitted under the FERC's Order 888, or the Transmission Provider's own Open Access Transmission Tariff (OATT) and is otherwise consistent with the Federal Power Act and the FERC's applicable standards and policies then in effect.

  A Transmission Provider's merchant function may reserve transfer capability to serve the non-reliability needs of its customers; however, it is necessary to reserve such capacity pursuant to applicable Network and Point-to-Point OATT similar to any other transmission customer. The Transmission Provider may reserve ATC for the import of power which is beyond the amount reserved for the reliability needs of it's Native Load customers, only to the extent permitted under FERC's Order 888, or the Transmission Provider's own OATT, consistent with the Federal Power Act and the FERC's applicable standards and policies then in effect.[6]

Consistent with Order 888, or the Transmission Provider's own OATT, a Transmission Provider may reserve either Network or Point-to-Point transmission service for its own resources and power purchases designated to serve Network Load. A Transmission Provider may also use the point-to-point tariff to reserve Firm transmission service where it has not made a purchase commitment. It must take such Firm point-to-point transmission service for its uncommitted purchases under the same terms and conditions of the tariff as it offers to others.

- Existing Commitments: Committed Uses associated with existing commitments at the time of the ATC determination are permissible. Determinations for these types of Committed Uses must be made available and are subject to evaluation upon request and in applicable dispute resolution forums.

- Firm Transmission Reservations for Energy Transactions: Transfer capability for energy transactions that can reasonably be expected to be consummated, such as expected hydro conditions, can be a Committed Use for the Transmission Provider (including an affiliated merchant business) to the extent consistent with the reservation provisions of the approved tariff by purchasing firm point-to-point transmission service from available transfer capability. Such transfer capability can be reserved for expected energy transactions, but must be released for Non-firm uses on a scheduling basis if unused or as otherwise required in accordance with the reservation priorities provided in the Transmission Provider's tariff.

Economy energy purchases (Non-firm purchases) by the Transmission Provider's merchant function can get service under secondary service for non-network resources on an as available basis at no additional "bookkeeping" charge (Section 28.4 of the FERC Open Access Transmission Tariff). If the Transmission Provider is using this service it should decrement Non-firm ATC for the purchase, but not Firm ATC. Firm point-to-point Transmission Service (PPTS) has reservation and curtailment priority over Secondary Service. Secondary Service has reservation and curtailment priority over Non-firm PPTS. Where the purchases are Firm and meet the requirements of a Network Resource, they qualify for a Firm transmission reservation and would be a decrement from the Firm ATC posting. To reserve Firm ATC for a Non-firm purchase or for where the Transmission Provider's merchant has not secured the purchase commitment or the purchase cannot otherwise qualify as a

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[6] Order 888 provides: at page 172 when discussing Reservation of Transmission Capacity, "We conclude that public utilities may reserve existing transmission capacity needed for native load growth and network transmission customer load growth reasonably forecasted within the utilities current planning horizon:" at page 191 when discussing Use of the Tariffs by the Rights Holder, "In the case of a public utility buying or selling at wholesale, the public utility must take service under the same tariff under which other wholesale sellers and buyers take service;" at page 323 when discussing Reservation Priority for Existing Firm Service Customers, "The transmission provider may reserve in its calculation of ATC transmission capacity necessary to accommodate native load growth reasonably forecasted in its planning horizon;" and at page 342 when discussing Network and Point-to-Point Customers' Uses of the System, "However we do not require any utility to take service to integrate resources and loads. If any transmission user (including the public utility) prefers to take flexible point-to-point service, they are free to do so."

Network Resource, the Transmission Provider's merchant must make a reservation of Firm PPTS just like it was any other Transmission Customer.

- Reserving transfer capability over multiple paths to secure capacity for a future undefined resource or purchase: Transmission Providers that have uncommitted purchases or resources as part of their resource plan to serve native load can reserve transfer capability on multiple paths until the uncommitted purchase or resource is defined. In such a case, the Transmission Provider should note on the OASIS that multiple paths are being reserved. If a request for transmission service is received for which there is inadequate ATC as a result of a multiple path reservation, the Transmission Provider should have the first right of refusal for use of the path. If the Transmission Provider exercises this right on a particular path, it should release its reservation on the other (multiple) paths.

- Good Faith Requests: Capacity may be reserved as "existing transmission commitments" for "good faith requests" for transmission service received by a Transmission Provider in accordance with applicable FERC or RTG request for service policy. ATC is decremented as specified by applicable FERC or regional policy.

- Information to be Provided: The following lists the types of assumptions and data that could be used in support of the determination of Committed Uses. Transmission Providers should make available the information used in their calculation of ATC values.

  Far-Term Environment (>1 year)

  - Load forecast
  - Load forecast error (range)
  - Standard for serving load
  - Breakdown of use by path
  - Breakdown of use by Time of Use period
  - Hydro and temperature forecasts
  - DSM, interruptible load assumptions
  - Redundancy of reserved paths
  - Resource outage standards (G-1? G-2?)
  - Resource assumptions (high/low hydro...)
  - Forecasted outages
  - Unit deratings
  - Resource dispatch assumptions
  - Purchases or sales to external parties
  - Wheeling contracts, including listings of Points of Receipt, Points of Delivery, and associated transmission demands at each point.

  Near-Term Environment (<1 month)

  - Standard for probability of serving load
  - Load forecasts (range of temperatures, hydro forecast, etc.)

- Resource outage standards (G-1? G-2?)
- Forecasts of generation
- Short-term wheeling arrangements, including listings of Points of Receipt, Points of Delivery, and associated transmission demands at each point.
- Purchases and sales with external parties.

6.3.4 Determination of Capacity Benefit Margin (CBM)

CBM is the amount of firm transmission transfer capability reserved by Load Serving Entities (LSEs) on the host transmission system where their load and generation resources are located, to enable access to generation from interconnected systems to meet generation reliability requirements. CBM is a uni-directional quantity with identifiable beneficiaries, and its use is intended only for the time of emergency generation deficiencies. CBM reservations may be sold on a non-firm basis.

Reservations should be made according to the applicable Transmission Provider's tariff. The determination of CBM reservations according to this Section 6.3.4 is only for purposes of determining required transmission capacity for generation reliability and is not intended to address any payment obligations associated with such reservations.

Each Transmission Provider should make its CBM values and calculation methodology publicly available, including a description of the procedure for the use of CBM in an energy emergency. Actual usage of CBM should be posted by the Transmission Provider.

The following components and considerations should be included in the determination of CBM. CBM may be set to zero.

- Replacement Reserves :

  Transmission for restoring operating reserves following a generator contingency, generally confined to the time period extending beyond the current scheduling hour that are required above the operating reserve level and are needed to accommodate generation reserves consistent with generation reliability criteria are included in CBM. CBM is only an import quantity and is reserved to meet the Transmission Customer's own potential resource contingencies.

- Reservations of Transmission for Purposes Other than Energy Delivery:

  In certain cases, a Transmission Provider with statutory obligation to serve native load may desire to reserve transmission for purposes other than energy delivery - for example, to provide a path for the import of ancillary services (such as spinning reserves) from another control area; or to allow imports on a different path (in a case where a control area requires a certain amount of unscheduled transfer capability for stability reasons). Similar to reserve sharing arrangements, such reservations are legitimate Committed Uses by a transmission Transmission

Provider to the extent that they are associated with meeting native load reliability requirements (rather than being economics-driven).

- Reservations of additional transfer capability for resource contingencies must be based upon reasonable, publicly available assumptions subject to evaluation in applicable dispute resolution proceedings. The methodology for determining the amount of reserves must be consistent with prudent utility practice, must be clearly documented and consistently followed, must be applied in a non-discriminatory manner, and must be auditable.

- Generation Patterns and Generation Outages:

  Many generation patterns and forced generation outages occur in the power system. These, including the number of generator contingencies, may be considered when determining Committed Uses, to the extent that deductions from ATC associated with these uncertainties use assumptions that are consistent with the planning and service reliability criteria which the Transmission Provider (with native load requirements) uses in serving its customers.[7]

Allowance for CBM generation reliability requirements should be determined in one of two ways, namely (1) using a Loss of Load Expectation (LOLE) probability calculation, or (2) deterministic based upon the largest single contingency. An LOLE of 1 day in 10 years is recommended. This calculation is made using commonly accepted probabilistic generation reliability techniques. The calculation is performed on a monthly basis. The generation requirement is then converted to a CBM requirement for each interconnection based upon historical purchases at peak times, typical load flow patterns and an assessment of adjacent and beyond control area reserves. The generation reliability requirement is updated at least annually.

The CBM requirement should be reviewed and appropriate updates made by the TPs at a minimum prior to each Operating Season.

Individual Transmission Provider CBM Methodologies shall consider in the CBM requirement only generation directly connected to the TP's system being used to serve load directly connected to that system. Generation directly connected to the TP's system which is committed to serve load on another system or which is not committed to serve load on any system shall not be included.

Interruptible load shall be included in the determination of CBM requirements.

[7] As uncertainty in forecasts diminishes, a Transmission Provider must release transmission capacity in a manner that is consistent with prudent utility practice, clearly documented, and consistently followed, applied in a non-discriminatory manner, and auditable.

GLOSSARY

Accepted Rating: a path rating obtained through the WSCC three-phase rating process that is the recognized and protected maximum capability of the path.

Available Transfer Capability (ATC): a measure of the transfer capability remaining in the physical transmission network for further commercial activity, over and above already-committed uses.

CCPG: Colorado Coordinated Planning Group under the umbrella of the Rocky Mountain Operation and Planning Group (RMOPG).

Capacity Benefit Margin (CBM): that amount of transmission transfer capability reserved by Load-Serving Entities with generation on the system up to the purchased/owned amount of transmission, to ensure access to generation from interconnected systems to meet generation reliability requirements.

Committed Uses: Five committed uses described in the RTG Governing Agreements as described in this document.

Curtailability: the right of a Transmission Provider to interrupt all or part of a transmission service due to constraints that reduce the capability of the transmission network to provide the transmission service. Transmission service can be curtailed as per the Transmission Providers OAT or contracts.

Firm Transmission Service: transmission service which cannot be interrupted by the Transmission Provider for economic reasons, but that can be curtailed for reliability reasons. This service is known as Non-Recallable transmission service in the NERC ATC documents.

Load Serving Entity: an entity located within a Transmission Provider's system whose primary function is to provide energy to end use customers. Also known as Energy Service Providers.

Native Load: existing and reasonably-forecasted customer load for which the Transmission Provider - by statute, franchise, contract or regulatory policy - has the obligation to plan, construct or operate its system to provide reliable service. For Transmission Providers not operating in a Retail Access environment, Native Load refers to the load within a Transmission Provider's service territory, to which it is also obligated to provide energy. For Transmission Providers operating in a Retail Access environment, Native Load refers to the load within the Transmission Provider's service territory, independent of the Energy Service Provider(s) serving energy to the load.

Network Resources: Designated resources used by a Transmission Customer to provide electric service to its Native Load consistent with reliability criteria generally accepted in the region.

Non-firm Transmission Service: transmission service which a Transmission Provider has the right to interrupt in whole or in part, for any reason, including economic, that is consistent with FERC policy and the provisions of the Transmission Provider's transmission service tariffs or contract provisions. This service is known as Recallable transmission service in the NERC ATC documents, or service offered on an as-available basis where a higher priority service requester may displace a lower priority service requester under the terms and conditions of the pro-forma tariff.

NRTA: Northwest Regional Transmission Association.

Operating Season: Those seasons that WSCC requires Operating Transfer Capability Studies to be performed (winter, spring and summer).

Parties: Colorado Coordinated Planning Group, Northwest Regional Transmission Association, Southwest Regional Transmission Association; Western Regional Transmission Association, and Western Systems Coordinating Council.

Recallability: the right of a Transmission Provider to interrupt all or part of a transmission service for any reason, including economic, that is consistent with FERC policy and the provisions of the Transmission Provider's transmission service tariff or contract provisions.

RTG Governing Agreements: Northwest Regional Transmission Association Governing Agreement, Southwest Regional Transmission Association Bylaws, and the Western Regional Transmission Association Governing Agreement.

SWRTA: Southwest Regional Transmission Association.

Total Transfer Capability (TTC): the amount of electric power that can be transferred over the interconnected transmission network in a reliable manner while meeting all of a specific set of defined pre- and post- contingency system conditions.

Transmission Customer: Any eligible customer (or its designated agent) that can or does execute a transmission service agreement or can or does receive transmission service. (FERC Definition – 18 CFR 37.3).

Transmission Provider: Any party that owns, controls, or operates facilities used for the transmission of electric energy in commerce.

Transmission Reliability Margin (TRM): that amount of transmission transfer capability necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions.

WRTA: Western Regional Transmission Association.

WSCC: Western Systems Coordinating Council

APPENDIX I

Standard for the Use of Netting for Firm ATC Calculations

In general, netting cannot be used to increase firm ATC. There is one exception to this general rule which can be done on a case-by-case basis at the Transmission Provider's discretion, provided that the criteria discussed below are adequately addressed.

If there is firm load on one side of the path in question and the generation resources scheduled to serve it are on the other side of the path, then firm ATC (and associated schedules) in the direction from the load to the generator can be increased by the scheduled amount from the generator to the load minus an adjustment for operating reserves and backup resources. This adjustment is determined by the location of the operating reserves and back up resources that would be deployed if the original resources serving the load were lost.

Any operating reserves or back up resources located on the same side of the path as the original resources maintain the firm counter-schedule, so the ATC in the direction from the load to the generator does not have to be decremented. If the operating reserves or back up resources come from the same side of the path as the load, then the counter-schedule would be lost. The ATC must then be decremented by the amount of these operating reserves and back up resources.

Each application of this exception must be analyzed carefully based upon the specific circumstances before firm netting is employed. A number of factors must be taken into consideration to determine how much of this firm netting can be reasonably allowed over any given transmission path. The factors that must be taken into account when determining the amount of load to net against include:

1. The size of the load. For firm netting, a forecast <u>minimum</u> load level that is reasonable for the time period under consideration should be used. The Transmission Provider must base the firm ATC calculations in these circumstances on a load level that can be expected to be present for the duration of any transactions that are netted against it.

2. Diversity of the load. Is the load a single large load that could be subject to interruption or is the load a diverse load area that has minimal risk of being completely blacked out?

3. Internal generation. Does the load area contain embedded generation resources?

4. Location of operating reserves and back-up resources. If the resources that are serving the load are lost, where will the operating reserves and back-up resources used to replace that generation come from? If they come from the same side of the path as load, then the counter-schedule is lost and there is the possibility that the path could be over-scheduled. Also, the reserves must be able to be deployed fast enough so that WSCC reliability standards for getting actual flows back within transfer limits are met.

Other factors may also need to be taken into account depending on the specific circumstances.

Example of Firm Netting Application:

Assume a path has a transfer capability of 1000MW in the east to west direction.
Assume that there is an actual load of 150MW on the east side of the path and 150MW of generation on the west side of the path that is used to serve it.
Firm east to west transactions of up to 1150MW can be accommodated across the path in the east to west direction since the load "nets out" 150MW due to the firm counter-schedule of the resource used to serve it in the west to east direction.

Approved at the October 25-26 WMIC meeting by WMIC.

Approved at the December 6, 2001 BOT meeting.