UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Facilities, Design, Connections and Maintenance)		
Mandatory Reliability Standards	**)**	**Docket No. RM07-3-000**

COMMENTS OF THE ISO/RTO COUNCIL

The ISO/RTO Council ("IRC")[1] respectfully submits these joint comments on the Commission's Notice of Proposed Rulemaking on *Facilities, Design, Connections and Maintenance Mandatory Reliability Standards* (the "NOPR").[2]

I. BACKGROUND

The Commmission is proposing to approve Reliability Standards developed by the North American Electric Reliability Corporation ("NERC").[3] The three new Reliability Standards were designated by NERC as follows:

- FAC-010-1 (System Operating Limits Methodology for the Planning Horizon);
- FAC-011-1 (System Operating Limits Methodology for the Operations

[1] The IRC is comprised of the Independent System Operator operating as the Alberta Electric System Operator ("AESO"), the California Independent System Operator Corporation ("CAISO"), Electric Reliability Council of Texas ("ERCOT"), the Independent Electricity System Operator of Ontario ("IESO"), ISO New England Inc. ("ISO-NE"), Midwest Independent Transmission System Operator, Inc. ("MISO"), New York Independent System Operator, Inc. ("NYISO"), PJM Interconnection, L.L.C. ("PJM") Southwest Power Pool, Inc. ("SPP") and New Brunswick System Operator ("NBSO"). The IESO, AESO and NBSO are not subject to the Commission's jurisdiction and their endorsement of these comments does not constitute agreement or acknowledgement that either can be subject to the Commission's jurisdiction. The IRC's mission is to work collaboratively to develop effective processes, tools and standard methods for improving competitive electricity markets across North America. In fulfilling this mission, it is the IRC's goal to provide a perspective that balances reliability standards with market practices so that each complements the other, thereby resulting in efficient, robust markets that provide competitive and reliable service to customers. Individual IRC members may file spearate comments in this proceeding.

[2] *Facilities, Design, Connections and Maintenance Mandatory Reliability Standards*, 120 FERC ¶ 62,155 (August 13, 2007) (the "NOPR").

[3] On February 3, 2007, the Commission issued Order No. 672 in which NERC was certified as the Electric Reliability Organization ("ERO"). *North American Electric Reliability Corp.*, 116 FERC ¶ 61,602 (ERO Certification Order), *order on reh'g & compliance*, 117 FERC ¶ 61,126 (2006), *order on compliance*, 118 FERC ¶ 61,030 (January 2007).

Horizon); and

- FAC-014-1 (Establish and Communicate System Operating Limits).[4]

In addition, NERC proposes the addition or revision of the following terms in the NERC Glossary of Terms Used in Reliability Standards (NERC glossary): "cascading outages," "delayed fault clearing," "Interconnection Reliability Operating Limit (IROL)," and "Interconnection Reliability Operating Limit T_v (IROL T_v)."[5]

II. COMMENTS

A. FAC-010-1 (System Operating Limits Methodology for the Planning Horizon).

The Commission proposes to approve Reliability Standard FAC-010-1 as a mandatory and enforceable Reliability Standard.[6]

(i). Consistency with Order No. 890.

FAC-010-1 applies to "planning authorities" and requires each planning authority to document its methods for determining system operating limits and to share the calculated limits with reliability entities.[7] The Commission seeks comment on whether the development of a methodology for calculation of SOLs for the planning horizon pursuant to proposed Reliability Standard FAC-010-1 and the calculation of ATC for the long-term pursuant to NERC's Modeling, Data, and Analysis (MOD) Reliability Standards results in the consistent use of assumptions as required by Order No. 890.[8] The Commission identified two concerns in particular.

[4] NOPR at P 4.
[5] NOPR at P 5.
[6] NOPR at P 15.
[7] NOPR at P 9 (the Commission in the NOPR at footnote 12 notes that Version 3 of the NERC's Reliability Functional Model replaced "planning authority" with the new term "planning coordinator").
[8] NOPR at P 17.

(1) Potential For Undue Discrimination in the Calculation of ATC.

> *Is there a potential for the exercise of undue discrimination against transmission customers where, for example, a planning authority's SOL methodology calls for the application of a single contingency in determining SOLs pursuant to FAC-010-1 and the reliability coordinator and planning authority calculate ATC for the long-term using the assumption of multiple contingencies? Do the Order No. 890 transparency requirements mitigate any potential for the exercise of undue discrimination in this respect*?[9]

The IRC agrees that there may be a potential for undue discrimination against customers of non-independent transmission providers, although it is not an issue where there is independent operation of the transmission grid. Non-independent transmission providers inherently have economic incentives to understate ATC on transmission paths that would be valuable to power sellers that compete with affiliates of transmission providers. In such circumstances, the methodology for calculating ATC and its application where transmission congestion exists will effectively determine whether competitors have access to the transmission grid.

These concerns, however, do not apply to independent RTOs and ISOs. RTOs/ISOs, as independent organizations, are free from any financial or ownership interest in the generation or transmission assets subject to their operational control or in the load served by those facilities. Thus, the incentive to discriminate and understate ATC simply does not exist in RTO/ISO markets. Indeed, just the opposite is true of RTOs/ISOs (*i.e.*, they have an incentive to maximize transmission flow, consistent with reliability considerations, in order to maximize the overall operational efficiency of the transmission grid under their control).

Moreover, the calculation of ATC is most relevant to those regions or markets

[9] NOPR at P 17 (1).

that offer advance physical reservations for transmission service. These concerns are not applicable within centralized energy markets where transmission customers schedule energy transactions, rather than transmission with the RTO/ISO. Within RTO/ISO markets, transmission service is not provided in terms of physical paths and calculations of ATC are not required. ATC is used at the RTO/ISO borders to comply with current Order No. 888 requirements, but ATC is simply not as important in RTO/ISO control areas where customers can buy and sell directly into the markets.

(2) Calculation of ATC, TTC and SOLs.

The Commission seeks comment on whether the SOLs developed pursuant to FAC-010-1 are essentially the same as TTC used for ATC calculation. If so, should NERC address SOLs, transfer capability and TTC in a coordinated and consistent manner?

The IRC is of the opinion that SOL, transfer capability and total transfer capability ("TTC") are parameters that address system reliability but they may be applied for different purposes. For example, transfer capability is studied to assess future needs or to identify potential constraints whereas an SOL study is intended to determine operating boundaries for system operating personnel to ensure near term reliability and a TTC calculation is used for determining provision of transmission services. Therefore, while SOL, transfer capability and TTC should be addressed in a coordinated manner in the standards, consistency should only be drawn in those areas that are common to all of them such as basic assumptions. The IRC would support NERC's efforts to develop the necessary standards and reference documents to achieve this directive.

(ii). Reliability Standard FAC-010-1:Other Matters.

(1) Transmission Planning Standards Loss of Shunt Devise.

Requirement R2.2 of FAC-010-1 requires a planning authority to consider various single contingencies including the loss of a shunt device. While the transmission planning (TPL) Reliability Standards implicitly require the consideration of the loss of a shunt device, they do not require this explicitly. Should the Commission clarify the TPL Reliability Standards by requiring the ERO to modify them to explicitly require the consideration of a shunt device, consistent with FAC-010-1?[10]

The contingencies listed under Category B in Table 1 of TOP-002-0 cover the type of events that the Planning Authority and Transmission Planner shall include in their planning studies to demonstrate that their portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels, over the range of forecast system demands. This requirement is generally consistent with the type of events that need to be included in the Planning Authority's SOL methodology stipulated in Requirement R2 of FAC-010-1. The IRC agrees with the Commission that it should stipulate that NERC modify the appropriate TPL Standards to explicitly require the consideration of a shunt devise to achieve total consistency in the single contigency sets between the two standards. If this path is pursued, the Commission should allow for an adequate transition period to allow for the collection and of information on modeling shunt devises for contingency purposes. The IRC supports making the requirements in the FAC and TPL standards complementary to each other.

[10] NOPR at P 29.

B. FAC-011-1 (System Opearting Limits Methodology for the Operations Horizon).

The Commission proposes to approve Reliability Standard FAC-011-1 as a mandatory and enforceable Reliability Standard.[11]

(i). Consistency with Order No. 890.

The Commission asks similar questions and raises similar concerns as those discussed above regarding Reliability Standard FAC-010-1 and the comments set forth in section II. A. (i). above apply equally to the this FAC-011-1.

(ii). Reliability Standard FAC-011-1: Other Matters.

(1) Load Greater Than Studied as a Contingency.

Requirement R2.3.2 provides that the system's response to a single contingency may include, *inter alia*, "[i]nterruption of other network customers, only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or, if the real-time operating conditions are more adverse than anticipated in the corresponding studies, *e.g.*, load greater than studied." The Commission seeks clarification from the ERO regarding the meaning of the phrase "if the real-time operating conditions are more adverse than anticipated in the corresponding studies, e.g., load greater than studied." In particular, the Commission is concerned whether this provision treats load forecast error as a contingency and as such would allow an interruption due to an inaccurate weather forecast.[12]

The IRC views the phrase "load greater than studied" as providing an example rather than qualifying what constitutes "if the real-time operating conditions are more adverse than studied." The IRC does not support the concept that load forecast error should

[11] NOPR at P 28.
[12] NOPR at P 32.

be treated as a contingency. In rare cases, load forecast error could result in not having sufficient resources to meet demand and operating reserve or in transmission being loaded to a level that when a contingency occurs, customers may be interrupted to observe transmission limitations. However, load forecast error itself should not be regarded as a contingency for assessing SOLs since its occurrence, albeit unpredicted on the day ahead, would normally allow time for implementing mitigating actions.

It is a condition to be studied in near real-time, not a "what-if" event as that of the sudden loss of a Bulk Electric System facility. Operating Reserve requirements are established to provide for the credible variations expected in the underlying assumptions used in study cases. This includes credible variations in the level of system load. Operating Reserves can be drawn upon when unanticipated load is encountered. In addition, there are standards requirements surrounding the restoration of reserves whenever reserves have been utilized for qualifying reasons. The IRC does not support expanding the definition of "contingency" from how it currently is defined to include such unanticipated loads. Operating Reserves are also defined in the NERC Glossary of Terms and includes "load forecasting error" as a condition for deployment.[13]

(2) Transmission Planning Standards Loss of Shunt Devise.

> *Requirement R2.2 of FAC-011-1 requires a reliability coordinator to consider various single contingencies including the loss of a shunt device. While the TPL Reliability Standards implicitly require the consideration of the loss of a shunt device, they do not require this explicitly. Should the the TPL Reliability Standards be modified to explicitly require the consideration of a shunt device, consistent with FAC-011-1?*[14]

[13] From the NERC Glosaary of Terms available at ftp://www.nerc.com/pub/sys/all_updl/standards/rs/Glossary_02May07.pdf

[14] NOPR at P 33.

The Commission asks a similar question as discussed above regarding Reliability Standard FAC-010-1. Thus, the comments set forth in section II. A. (ii) above apply equally to the this Reliability Standard FAC-011-1.

C. Proposed Definitions.

The Commission believes that there could be multiple interpretations of some of the terms contained in the proposed addition or revision to four terms in the NERC glossary (*i.e.* Cascading Outages, Delayed Fault Clearing, Interconnection Reliability Limit [IROL], and Interconnection Reliability Operating Limit T_v (IROL T_v).[15] As such, the Commission proposes to provide its clarification of Cascading Outages, Interconnection Reliability Operating Limit, and Interconnection Reliability Operating Limit T_V to be consistent with directives in Order No. 693.

(1) Cascading Outages Definition.

For purposes of compliance, the Commission proposes to direct NERC to consider the loss of facilities in the bulk electric systems that are beyond those that would be removed from service by primary or backup protective relaying associated with the initiating event to be a Cascading Outage. With this understanding of the phrase, the Commission proposes to accept the definition in FAC-014.[16]

The IRC understands the term Cascading Outage to generally mean unpredicted or uncontrolled tripping of bulk electric system facilities beyond those assessed and identified ahead of the event occurrence. Studies are usually conducted to predict the extent of multiple outages that may result from protective relay operations directly or indirectly in response to the initiating event. In this context, protective relays may include

[15] NOPR at P 38.
[16] NOPR at P 40.

primary protection; backup protective relays may include secondary protection, zone 2 protection and special protection systems that operate to contain the impacts of an event to a pre-determined (through studies)localized area.

In order for the industry to have an unambiguous interpretation of the proposed revised definition, in particular as it relates to protection relays, the IRC seeks the Commission's clarification on what the phrase "backup protective relaying" means, and whether or not planned operation of a special protection system to contain the impacts of multiple outages is regarded as a backup protection.

(2) IROL Definition.

The revised definition of IROL in the approved NERC glossary ["The value (such as MW, MVar, Amperes, Frequency or Volts) derived from, or a subset of the System Operating Limits, which if exceeded, could expose a widespread area of the Bulk Electric System to instability, uncontrolled separation(s) or cascading outages"] is consistent with the intent of the statute with the exception of the phrase "that adversely impacts the reliability of the bulk electric system." This may give the impression that violation of some IROLs that do not adversely impact the reliability of the bulk electric system are acceptable. The Commission proposes to accept the definition in FAC-014 with the understanding that all IROLs impact bulk electric system reliability.[17]

The IRC concurs with the Commission that all IROLs impact Bulk Electric System Reliability.

In Order No. 693, the Commission identified two interpretations of when an entity exceeds an IROL.[18] The definition of IROL T_v does not distinguish between those two

[17] NOPR at P 42.
[18] *See* Order No. 693 at P 946 & n.303.

interpretations. The Commission proposes to accept the definition in FAC-014 ["(t)he maximum time that an Interconnection Reliability Operating Limit can be violated before the risk to the interconnection or other Reliability Coordinator Area(s) becomes greater than acceptable. Each Interconnection Reliability Operating Limit's T_v shall be less than or equal to 30 minutes"] with the understanding that the only time it is acceptable to violate an IROL is in the limited time after a contingency has occurred and the operators are taking action to eliminate the violation.

The IRC disagrees that the only time an IROL can be exceeded is for a contingency. Tv should be less than or equal to 30 minutes with the understanding that the only time it is acceptable to violate an IROL is in the limited time after a contingency has occurred and the operators are taking action to eliminate the violation. The IRC would, however, propose to expand this understanding to include the situation where no contingencies have occurred but the IROL is exceeded due to system condition changes, such as unanticipated external interchange schedules, redispatch, morning and evening load pick-up, or other events that cause a rapid change in transmission loading.

III. CONCLUSION

For the reasons set forth above the IRC respectfully requests that the Commission adopt the IRC recommendations set forth above and expeditiously issue a final rule in this proceeding.

Respectfully submitted,

/s/ Craig Glazer
Craig Glazer
Vice President – Federal Government Policy
Steven R. Pincus – Senior Counsel
Jacqulyn Hugee – Senior Counsel
PJM Interconnection, L.L.C.
1200 G Street, NW, Suite 600
Washington, D.C., 20005

/s/ *Stephen G. Kozey*
Stephen G. Kozey
Vice President and General Counsel
Midwest Independent Transmission System Operator, Inc.
701 City Center Drive
Carmel, Indiana, 46032

/s/ Theodore J. Paradise
Theodore J. Paradise
Senior Regulatory Counsel
ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040

/s/ Anthony J. Ivancovich
Nancy Saracino
Vice President, General Counsel & Corporate Secretary
Anthony J. Ivancovich
Assistant General Counsel
California Independent System Operator Corporation
151 Blue Ravine Road
Folsom, CA 95630

/s/ Kim Warren
Kim Warren
Manager, Regulatory Affairs
Independent Electricity System Operator of Ontario
655 Bay Street, Suite 410
Toronto, Ontario, M5G-2K4

Robert E. Fernandez
Robert E. Fernandez
Vice President and General Counsel
Elaine Robinson
Director of Regulatory Affairs
New York Independent System Operator, Inc.
290 Washington Avenue Extension
Albany, N.Y. 12203

/s/ Diana Pommen
Diana Pommen
Director Business Operations
Independent System Operator operating as the Alberta Electric System Operator
Calgary Place
2500 330 - 5th Avenue SW
Calgary, AB T2P 0L4

/s/ Michael G. Grable
Michael G. Grable
Assistant General Counsel
Electric Reliability Council of Texas
7620 Metro Center Drive
Austin, TX 78744

/s/ Stacy Duckett
Stacy Duckett
General Counsel & Corporate Secretary
Southwest Power Pool
415 North McKinley
#140, Plaza West
Little Rock, AR 72205-3020

September 19, 2007