UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Remedying Undue Discrimination	)	
Through Open Access Transmission Service	)	**Docket No. RM01-12-000**
And Standard Electricity Market Design	)	

COMMENTS OF THE NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

I. INTRODUCTION

The North American Electric Reliability Council (NERC) appreciates the opportunity to provide these comments on the Commission's Notice of Proposed Rulemaking on Standard Market Design (SMD NOPR).[1] NERC's comments are in two parts; the first part focuses on those aspects of the proposed rule that have the potential to affect the reliable planning and operation of the bulk electric systems in North America; the second part focuses on the proposed cyber-security standards.

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[1] NERC is a not-for-profit company formed as a result of the Northeast blackout in 1965 to promote the reliability of the bulk electric systems that serve North America. NERC works with all segments of the electric industry as well as customers to "keep the lights on" by developing and encouraging compliance with rules for the reliable operation of these systems. NERC membership comprises ten Regional Reliability Councils that account for virtually all the electricity supplied in the United States, Canada, and a portion of Baja California Norte, Mexico.

II. EXECUTIVE SUMMARY

Part One — Reliability

The restructuring of the electric industry and the evolution of competitive wholesale electric markets has changed the way the reliability of the bulk electric system is managed. Restructuring is occurring at different paces in different parts of North America, while at the same time the bulk electric system everywhere is being used more aggressively and in ways for which it was not designed.

The interconnected grid operates as one very large machine, comprising generators, transmission lines, substations and customers throughout the United States, Canada and Mexico. Regardless of how and at what pace markets develop, industry stakeholders and regulators must not lose sight of the unique nature of the electric grid as we devise systems to maintain reliability in a competitive environment. NERC's comments identify those issues that need to be addressed to maintain reliability under any future market design.

NERC's reliability comments focus on those aspects of the proposed rulemaking that have the potential to affect the reliable planning and operation of the bulk electric systems in North America. Although these comments address numerous aspects of the SMD NOPR, NERC's primary areas of concern focus on five main areas:

1. Ensuring that independence of the Independent Transmission Provider (ITP) is clarified and that the reliability functions that the ITP will be responsible for providing under the NERC Functional Model are clearly identified.
2. Ensuring that parallel flow impacts between ITPs are coordinated, that curtailment priorities are clarified, and that a backstop congestion management procedure is in place prior to the implementation of SMD.
3. Ensuring that the relationships between interconnected operations services and the ancillary services are clarified, and that all ancillary services necessary for the reliable operation of the grid are correctly identified and included in the SMD.

4. Ensuring that the proposed resource adequacy requirements will ensure an adequate and reliable bulk electric system.
5. Ensuring that the methodologies used to assess transmission capacity and uses are consistent with established design and operating criteria.

1. The Role of the Independent Transmission Provider

Concerning the role of the ITP, NERC requests clarification of the Commission's intent when it says that the ITP can own, control or operate transmission, and therefore may have interest in transmission assets, yet must be independent from any market participant. Based upon the definitions provided in the NOPR, it is unclear how the Commission will ensure that an entity that owns and controls transmission assets will not unduly discriminate in favor of its own transmission interests when carrying out operational and planning decisions.

NERC believes that the Functional Model remains relevant under the proposed SMD. However, NERC seeks clarification regarding the Commission's intent for certain reliability responsibilities of the ITP in relation to the Functional Model. Clarification of these issues will help to ensure that the Functional Model remains relevant within an ITP structure.

2. Congestion Management and Parallel Flow Impacts

The NOPR proposes that transmission system congestion will be managed with price-based mechanisms offered by Locational Marginal Pricing (LMP). The NOPR also proposes that ITPs will need to establish procedures to off-load the transmission system when market approaches are insufficient. However, the NOPR lacks sufficient detail in several areas relating to congestion management, including how to address the impacts of parallel flows among ITP systems, the need for backstop reliability protocols when the market fails to reach a feasible condition for reliable operation with available resources, and the relative priorities of transmission users for the purpose of effectively curtailing uses if the market fails.

NERC strongly believes that congestion management procedures must be coordinated among the ITPs. NERC recommends that the Commission require ITPs and other transmission providers to coordinate, and to the extent practical standardize, their procedures for addressing parallel flow impacts. NERC, working closely with ITPs and industry stakeholders, offers to facilitate the development of backstop transmission loading relief procedures that ensure the continued reliability of the Interconnections in North America, are consistent with an SMD framework, and respect the Commission's clarifications regarding curtailment and scheduling priorities. NERC also requests that the Commission further clarify its policy on the relative curtailment and scheduling priorities of transmission users under the Network Access Service and other users. Finally, NERC identifies several other technical issues associated with congestion management and loop flows that must be addressed in the Final Rule.

3. Interconnected Operations Services

NERC seeks to clarify the relationships between various Interconnected Operations Services (IOS) and the ancillary services identified in the NOPR. NERC's comments identify those IOS and ancillary services that are adequately addressed by the SMD and those that are not. NERC respectfully requests that the Commission encourage ITPs to consider NERC's definitions and measures of IOS when developing their ancillary services definitions and protocols. Specifically, our comments recommend that Primary Frequency Response be considered either as a required ancillary service within the SMD framework or as a requirement of interconnecting and operating a generator. NERC strongly recommends that System Black Start Capability become a required ancillary service in the SMD framework. Finally, NERC recommends that Energy Imbalance be removed as an ancillary service since it is a measure that allows each generator and load to settle differences between scheduled and actual uses in the real-time market.

4. Resource Adequacy

NERC strongly believes that NERC should develop minimum resource adequacy standards and related criteria. NERC and the regions have a long history of assessing resource adequacy and believe that this role should be continued. NERC finds that the resource adequacy requirements proposed in the NOPR will not ensure reliability and recommends that alternatives to a fixed capacity requirement be considered. NERC recommends that data requirements be established to implement resource adequacy and regional planning, that a longer planning horizon needs to be established to implement a resource adequacy requirement, and that a capacity penalty is needed to ensure adequate resources; and requests further clarification of the details of the regional planning proposal.

5. *Technical Issues*

NERC's comments address additional technical concerns as well. Specifically, NERC recommends that Independent Transmission Providers work closely with individual transmission owners to ensure the most accurate calculation of ATC, and ensure that the allocation of any firm transmission rights be based upon appropriate simultaneous feasibility tests.

Part Two — Cyber-Security Standards

NERC supports the Commission's adoption of cyber-security standards. Wholesale electric grid operations are highly interdependent, and a failure of one part of the generation, transmission or grid management system can compromise the reliable operation of a major portion of the regional grid. Similarly, the wholesale electric market — as a network of economic transactions and interdependencies — relies on the continuing reliable operation of not only physical grid resources, but also the operational infrastructure of monitoring, dispatch and market software and systems. Because of this mutual vulnerability and interdependence, it is necessary to safeguard the critical cyber assets that support electric grid and wholesale market operations by establishing minimum standards for all those who participate in any way in electric wholesale market operations.

NERC's Critical Infrastructure Protection Advisory Group ("CIPAG") developed the draft security standards that were included as Appendix G to the Commission's standard market design notice of proposed rulemaking. After reviewing the comments filed in response to the

NOPR and based upon further discussion within the industry, NERC is recommending changes to Appendix G.

III. PART ONE — RELIABILITY

The interconnected grid operates as one very large machine and this must be kept in mind as we devise systems to maintain reliability in a competitive environment. NERC's comments identify those issues that need to be addressed to maintain reliability under any future market design.

A. The Role of the Independent Transmission Provider

In this section, NERC:

- Requests clarification of the Commission's intent when it says that the Independent Transmission Provider (ITP) can own, control or operate transmission, and therefore may have interest in transmission assets, yet must be independent from any other market participant.
- Requests clarification regarding the Commission's intent for functional responsibilities of the ITP in relation to the Functional Model.

1. The Definition of an Independent Transmission Provider Needs Clarification.

As the following selections from the NOPR illustrate, clarification is needed concerning the definition of an ITP.

"To remedy this undue discrimination, transmission service must be provided by an independent entity. Therefore, we propose to require all public utilities that own, control or operate facilities for the transmission of electric service in interstate commerce to: (1) meet the definition of Independent Transmission Provider, (2) turn over the operation of its transmission facilities to an RTO that meets the definition of Independent Transmission Provider, or (3) contract with an entity that meets the definition of Independent Transmission Provider to operate its transmission facilities."[2]

"An Independent Transmission Provider is any public utility that owns, controls or operates facilities used for the transmission of electric energy in interstate commerce, that administers the day-ahead and real-time energy and ancillary services market in connection with its provision of transmission services pursuant to the SMD Tariff, and is independent (i.e., has no financial interest, either directly or through an affiliate, in any market participant in the region in which it provides transmission services or in neighboring regions)."[3]

The NOPR in the first instance proposes that all public utilities that own, control or operate facilities for transmission of electric service meet the definition of an ITP or turn over the operation of their transmission facilities to an RTO or an entity that meets the definition of an ITP. Yet in the second instance, the NOPR states that an ITP can also own, control or operate facilities for the transmission of electric service. NERC interprets this to mean that all transmission will need to be under the operational control of an entity that meets the requirements of an ITP, which includes requiring that entity to be independent of any other market participant. As an owner and/or operator of transmission facilities, and as the administrator of day-ahead and real-time energy and ancillary services markets, the ITP is by definition a market participant. NERC requests clarification of the Commission's intent so that NERC can properly reflect this intent in its development of reliability standards that may apply to ITPs in their performance of reliability functions defined in the Functional Model.

2. The Functional Model Remains Relevant Under the Proposed SMD, But Clarification is Needed on Reliability Functions the ITP Must Perform.

NERC appreciates the Commission's reference to and support for the Functional Model developed by NERC.[4] NERC believes that the Functional Model is an effective foundation on

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[2] NOPR ¶ 125.

[3] NOPR ¶ 126.

[4] NOPR Appendix C, footnote 5.

which to base NERC's new reliability standards and on which others can base the development of business practice standards and communications protocols. NERC is presently reviewing the model to ensure that it will integrate successfully with the proposed SMD. So far, we have not detected any feature of the SMD NOPR that the Functional Model will not accommodate. We also recognize that the model may need to accommodate other market designs because some areas of North America may, for various reasons, operate under different (i.e., non-SMD) market structures, at least during a transition period.

The NOPR does raise some questions about the various functions that the ITP must – or may – perform. Clarification will help NERC to ensure that the Functional Model remains compatible and successfully integrates with the ITP structure and functions envisioned by the Commission.

According to the NOPR: "[a]n Independent Transmission Provider is any public utility that owns, controls or operates facilities used for the transmission of electric energy in interstate commerce, that administers the day-ahead and real-time energy and ancillary services markets in connection with its provision of transmission services pursuant to the SMD Tariff, and that is independent."[5] From this, NERC infers that the ITP will be responsible for the following functions identified in the Functional Model:

1. **Transmission Owner and Transmission Operator**. According to the NOPR, the ITP "…owns, controls or operates facilities used for the transmission of electric energy in interstate commerce." Therefore, it appears that the ITP can perform the transmission owner and transmission operator functions from the Functional Model.

2. **Transmission Service Provider**. The NOPR states that the ITP provides "…transmission services pursuant to the SMD Tariff…" In NERC's view, this is clearly the transmission service provider defined in the Functional Model.

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[5] NOPR ¶15(2) and "Standard Market Design Pro Forma Open Access Transmission Tariff" § I.A.1.

3. **Balancing Authority.** The Tariff lists eight services that the ITP must provide to support the real-time regulation market.[6] One service in particular we note is: (iii) "Provide Base Point Signals to Generators providing Regulation to direct the Generator's output." NERC believes the ITP can meet this obligation either by serving as the balancing authority, or by relying on multiple balancing authorities within the ITP's service area.

4. **Reliability Authority.** Although this is not explicitly stated in the NOPR, there is nothing obvious that would preclude the ITP from serving as the reliability authority. In many parts of the Tariff, the term "*local reliability authority*" is used. NERC understands that this term is referring to Regional Reliability Council requirements, guides, and standards, and asks for clarification if this is incorrect.

B. Congestion Management and the Coordination of Parallel Flow Impacts

The NOPR proposes that transmission system congestion will be managed with price-based mechanisms offered by Locational Marginal Pricing (LMP). NERC supports congestion management approaches that provide an economic basis for allocating use of scarce transmission resources in a manner that respects system operating security limits and assures reliable operation of the bulk electric system. However, the NOPR lacks sufficient detail in several areas related to congestion management: a) how to address the impacts of parallel flows among different ITPs; b) the need for backstop reliability protocols if the market fails to mitigate operating security limits within the required time; and c) the relative priorities of transmission uses for the purpose of effectively curtailing uses to return the system to a safe operating state if the market fails to do so.

In this section, NERC:

- Recommends that the Commission require ITPs to coordinate, and to the extent practical standardize, their procedures for addressing parallel flow impacts.

[6] Tariff § III.G.5.2.

- Requests that the Commission further clarify its policy on the relative curtailment and scheduling priorities of transmission users under the Network Access Service and other users.
- Recommends that NERC, working closely with ITPs and industry stakeholders, facilitate the development of backstop transmission loading relief procedures that ensure the continued reliable operation of interconnected bulk electric systems, are consistent with an SMD framework, and respect the Commission's clarifications regarding curtailment and scheduling priorities.
- Raises other issues associated with congestion management and parallel flows that must be addressed in the Final Rule.

1. Parallel Flow Impacts Among ITPs Must Be Coordinated.

Coordinating system operations among ITPs and between ITPs and non-ITP systems to account for and manage parallel flow impacts is critical to maintaining reliability. The Tariff states that "[t]he ITP must develop procedures addressing nondiscriminatory curtailment of parallel flows involving more than one transmission system."[7] This statement is incomplete because it understates the fact that these procedures must be coordinated and, to the extent practical, standardized among ITPs. The market dispatch of one ITP will simultaneously cause parallel, unscheduled flows on the systems of all other systems in the same Interconnection. Short of having a single market operator throughout an Interconnection or perfect coupling of LMP models and congestion information (which cannot be expected for at least several years), ITPs will need to closely coordinate unscheduled parallel flow impacts with each other and with transmission systems that are not part of another ITP.

When addressing parallel flows that can result in overloading other systems, the first priority is to establish a backstop transmission loading relief mechanism that is coordinated among ITPs and non-ITP systems (described further in the next section). There must be mechanisms in the

[7] Tarriff § II.B.9.3.

day-ahead and real-time markets to coordinate the reduction of unscheduled flows when they adversely impact the reliable operations of other systems.

ITPs and non-ITP systems within the same Interconnection must work with one another directly or through their reliability authority(ies) to ensure inter-area coordination. This is especially important when considering the effects of voltage and stability limits, where cascading voltage collapse or instability can quickly spread to other parts of an Interconnection. Specifically, as the ITP develops its day-ahead economic dispatch, it needs to share this dispatch information with neighboring ITPs and reliability authorities so that the reliability authorities can conduct their reliability analyses and understand overall system conditions. Parallel flow impacts also need to be anticipated in the planning horizon and in the determination of transfer capabilities, as noted later in these comments.

The Commission asks, "[S]hould a similar pricing methodology be applied to parallel path flows? Parallel path flows are comparable in that one region benefits by the use of a neighboring region's transmission facilities. Parallel path flows are currently resolved through cooperation. An alternative method would be to price all uses of the grid. We seek comment as to how cost impacts of parallel path flows across regional borders should be addressed."[8]

This question is at the heart of the parallel flow issue. Because the NOPR proposes to have each customer "subject to the cost of congestion between its chosen receipt and delivery points,"[9] (with some having price certainty afforded by Congestion Revenue Rights), the motivation for ignoring unscheduled parallel flows is diminished. The potential reliability impact is that the participants in each market could have economic incentives to rely on unscheduled (and therefore free) parallel flows on neighboring systems and not take steps to account for them. ITPs must have some mechanism, financial or otherwise, to coordinate and manage parallel flows to ensure reliable operations. Some have suggested that coordination of prices at the LMP model boundaries can suffice. However, that is unlikely to be fully effective

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[8] NOPR ¶ 190.

[9] NOPR ¶ 144.

for several years during a transition period. An alternative is to use an Interconnection-wide power flow model, such as the Interchange Distribution Calculator, on an interim basis for such coordination.

A related question is whether an ITP that runs out of resources to meet demand while respecting transmission constraints should request relief from other systems before curtailing firm loads. Historically, when systems have exhausted their own curtailment and redispatch options, they would be able to ask for and receive assistance from neighboring systems before resorting to the curtailment of firm load. Under the proposed SMD, is that cooperation still required or expected among ITPs?

2. A Backstop Curtailment Procedure is Needed and Curtailment Priorities Must Be Established.

The NOPR references the need for the ITP to establish procedures to reduce loadings on the transmission system to protect reliability when the market approach is insufficient.[10] Those procedures, which address transmission loading relief and energy emergencies, must be coordinated among all transmission operators within an Interconnection. The NOPR states that "[u]nder Network Access Service, procedures for addressing non-discriminatory curtailment of parallel flows will continue to be needed under emergency conditions when the use of a regional congestion management procedure set out in this proposed rule does not completely relieve a constraint."[11] NERC agrees and believes that the Functional Model provides a framework for such coordination. However, how this framework is implemented will be substantially different under the proposed standard market design as compared to the relief procedures used under the Order No. 888 contract path model. NERC expects the backstop transmission loading relief procedures to continue to adapt during a transition period over the next few years. It is important to note that successful LMP-based markets should drastically

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[10] Tariff § II.B.9.3, "[The Independent Transmission Provider must develop procedures addressing nondiscriminatory curtailment of parallel flows involving more than one transmission system.]"

[11] NOPR ¶ 161.

reduce the need for non-economic curtailments. However, a backstop relief mechanism is essential to reliability.

In developing backstop procedures to ensure effective and nondiscriminatory curtailment of parallel flows that threaten reliability, ITPs and Reliability Authorities will need further clarifications from the Commission on the curtailment priorities of users under Network Access Service and other tariffs or grandfathered agreements. These clarifications are necessary to ensure that practical relief measures can be developed to allow effective and timely unloading of overloaded transmission facilities. NERC requests that the Commission further clarify its policy on curtailment priorities by addressing the issues outlined below.

The NOPR states that the curtailment priorities are such that non-CRR protected transmission uses are cut first on a pro-rata basis. If further relief is required, then CRR protected transmission uses are cut on a pro rata basis.[12,13] NERC is concerned that such a limited number of distinguishable categories for curtailment priority (with CRRs or without) could lead to inefficient and ineffective curtailment procedures. For example, implementing a high number of small pro-rata curtailments over a very broad class of users may be difficult to manage and still may not result in effective and timely relief. Also, the concept of pro-rata cuts is overly simplistic, as each transmission use will have some impact on an overloaded facility, with some being infinitesimally small.

Curtailment priorities and procedures must respect the reliability requirements for relief steps that are practical, timely, and effective. Several policy questions impact these reliability requirements. Should these cuts be made pro-rata based on flow impact on the active constraint or on the total MW amount of the transaction? Should there be a threshold of impact before a transaction is curtailed? Should customers with longer term CRRs have priority over those with shorter-term rights? Can the ITP seek alternative, non-discriminatory approaches that achieve

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[12] NOPR ¶ 158-161.

[13] NOPR ¶ 159: "To the extent practicable, when system conditions require curtailment (in real time) that cannot be resolved through the congestion management system, the Independent Transmission Provider should curtail the customers whose transactions contribute to the constraint on a pro rata basis."

more effective and timely transmission relief while mitigating the impacts to transmission users, such as curtailing a targeted set of uses that provide the most immediate relief? What are the curtailment priorities of imports, exports, and "through" transactions when compared with uses internal to the ITP? What are the rights of grandfathered contracts holders relative to other users in the establishment of curtailment priorities?

Finally, there appears to be confusion between scheduling priorities and curtailment priorities. Under the Order No. 888 pro forma tariff, scheduling and curtailment carry different priority structures. It is not clear what is intended in the SMD NOPR. The NOPR states "[i]n any hour in which the Independent Transmission Provider is unable to accept all requested schedules for Transmission Service at the applicable Day-Ahead Transmission Usage Charges, holders of Receipt Point-to-Delivery Point Congestion Revenue Rights shall have scheduling priority from their designated Receipt Points to their designated ABC Independent Transmission Provider Delivery Points over Customers that do not hold Congestion Revenue Rights. [The Independent Transmission Provider shall develop a method for determining how to implement such priority, which shall be inserted here.]"[14] It is not clear that scheduling priorities are intended to be the same as curtailment priorities. If they are, then a similar problem occurs — the "bucket" is so large that there is no practical way to determine who should be scheduled and who should not.

NERC requests that the Commission provide further policy details on the curtailment priorities of users (and separately on the priorities of users for the purpose of scheduling). Once this guidance is provided, NERC offers to facilitate an industry effort to develop backstop transmission loading relief procedures reflecting the Commission's policies on scheduling and curtailment priorities. Such curtailment procedures must be consistent from one reliability authority to another and must also be fair, non-discriminatory, effective in achieving loading relief, and also practical. At the same time, consideration must be given to allowing variations to those procedures that serve the needs and priorities of market participants in that region.

[14] Paragraph 159 also states "In addition, we propose that to the extent the Independent Transmission Provider is unable to schedule all requests for service made through the day-ahead scheduling process, those customers with Congestion Revenue Rights for their requested receipt point-delivery point combinations should be scheduled first."

3. The NOPR Raises Other Congestion Management Issues That Must Be Addressed in the Final Rule.

a. Clarification is Needed on Whether a Congestion Revenue Right Conveys a Physical Transfer Right.

The NOPR's description of curtailment priorities suggests that CRRs convey a physical right to use the transmission grid. The NOPR states that "[o]nce the day-ahead market closes, all customers pay for the service requested and, if they hold Congestion Revenue Rights, are paid congestion costs associated with those rights. Thus, the customer has bought and paid for a quantity of transmission at a specified price."[15] This last sentence implies a purchase of a transmission right, when in fact any customer with Network Access Service already has the right for transmission use and acquiring a CRR is simply a hedge against congestion costs. The understanding that CRRs convey a physical right to transmission is bolstered by the suggestion that scheduling and curtailment priorities should be given to those who have CRRs.

The NOPR further suggests that CRRs can be redirected or reconfigured (the injection point or extraction point changed).[16] The NOPR states that "the customer could request a "reconfiguration" of the CRRs it holds, i.e., the customer could turn in the CRRs for the old receipt and/or delivery point and request CRRs from the new receipt point or to the new delivery point."[17] This paragraph continues: "In addition, Network Access Service allows the customer (1) to trade (reassign) its Congestion Revenue Rights and (2) to access points, which, under the current pro forma tariff, are secondary points that may be fully subscribed, by paying all applicable congestion charges."

These statements are in conflict with the concept of CRRs as purely financial hedges and not rights to physical transfers. The NOPR appears to confirm this concept by stating "A Network

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[15] NOPR ¶ 208.

[16] NOPR ¶ 156 and footnote 97.

[17] NOPR ¶ 139.

Access Service customer can essentially access any point simply by requesting it through the day-ahead scheduling process or real-time transactions (and be willing to pay congestion costs and losses). To the extent the customer wanted to avoid the cost of congestion for the transaction, it could retain its existing Congestion Revenue Rights and acquire additional Congestion Revenue Rights for its new receipt and delivery points through an auction or secondary market."[18] Before it can be determined whether the NOPR's approach to CRRs raises reliability issues, NERC requests clarification as to whether the Commission intends for CRRs to be purely financial hedges, or to both provide a financial hedge and convey a right (or higher priority) to physically flow electricity from one point of the system to another.

b. More Information Exchange and Expanded Tools Are Needed.

The data exchange necessary to reliably implement LMP dispatch over wide areas will need to use considerably more sophisticated reliability tools than the current "tagging" system and Interchange Distribution Calculator that the Eastern Interconnection reliability authorities use today. The industry developed transaction tagging as a means to transfer information related to market uses of the transmission system to the system operators. Today, this information is not only exchanged between market participants and system operators, but is shared among system operators and reliability authorities for the purpose of coordinating the reliability impacts of parallel flows. Because uses under Order No. 888 were transaction-based and path-based, the tag captures transmission rights and energy profile information for each transaction.

Under the proposed SMD, the concept of a transaction as a bundle of energy flowing from a source to a sink along a reserved path is no longer valid. Bilateral transactions and self-schedules do retain some of the attributes of a tag, such as designation of a source and sink and a MW amount. However, the proposed Network Access Service removes the path-related information requirements.

To implement SMD, a new understanding is needed of how transmission uses will be modeled to allow two things to occur in a consistent and reliable manner: 1) market participants convey

[18] Need ¶ cite.

the necessary details of bilateral schedules to the ITP; and 2) ITPs can share information on transmission uses with other ITPs and non-ITP systems in the same Interconnection for purposes of reliability analyses. This latter requirement presents new challenges in that some of the uses are bilateral, while spot market uses are simply depicted as source or load points, with the corresponding other half of the transaction unknown. For reliability purposes, ITPs must be able to exchange day ahead as well as near real-time information on transmission uses so that other systems can model the reliability impacts. Information sharing requirements must be standardized to ensure seamless exchange among ITPs.

The above discussion points out the strong need within the SMD framework for robust data exchange protocols and communications infrastructure among ITPs to allow them to exchange real time information needed for reliable market operation. The Electronic Scheduling Collaborative, North American Energy Standards Board, Electric Power Research Institute, and NERC are working together to develop the comprehensive communications protocols and data sharing that will be necessary to enable the markets to work efficiently and reliably.

c. Commercial Delivery Points Must Be Coordinated.

The Commission needs to ensure that ITPs coordinate commercial points of receipt and delivery at the interfaces between systems. This has been a long standing issue and an impediment to seamless markets. From a reliability standpoint, the commercial delivery points must also have reasonable relationship to physical delivery points. This is not to say the market design requires physical transaction scheduling; just that reliability information must be exchanged regarding the physical injections and loads at points that model system topology.

d. There is a Potential for "Backdoor" Transactions to Avoid Congestion Charges.

The NOPR discusses several market flaws that the SMD is intended to address.[19] One issue that may not be adequately addressed can be described as a "backdoor" transaction to avoid congestion charges. This issue could arise when there is less than a full coordination of seams

[19] Appendix C.

between LMP systems. For example, assume Generator A desires to sell to Load B within the same ITP, but together they have insufficient CRRs to cover the high cost of congestion on a heavily loaded constraint between them. Generator A instead sells off the system away from the constraint and through a series of wheeling transactions on other ITPs, transfers the energy around the constraint and through systems with lower congestion costs. The energy is then imported to Load B from a direction that appears to be "helping" the constraint. Of course, the real power flows on the system will remain the same.

The reliability issue that is raised is that the actual flow through the constrained interface will be no different because the energy will still flow directly from A to B. However, instead of being modeled, the flow will appear as an unscheduled parallel flow from other systems. This type of activity should be discovered through the exchange of information on imports and exports among ITPs and market monitors.

C. Interconnected Operations Services

This section reviews and comments on the ancillary services proposed in the NOPR and makes extensive reference to NERC's "Interconnected Operations Services Reference Document," which was previously filed with the Commission under Docket No. RM01-12-000.[20]

In this section, NERC:

- Clarifies the relationships between various Interconnected Operations Services (IOS) and ancillary services, and identifies those IOS that are adequately addressed by the SMD and those that are not.
- Asks the Commission to encourage ITPs to consider NERC's definitions and measures of IOS when developing their ancillary services definitions and protocols.

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[20] This document is available at ftp://www.nerc.com/pub/sys/all_updl/docs/ferc/IOS_CoverRef_Doc_022502.pdf.

- Recommends that Primary Frequency Response be considered either as a required ancillary service within the SMD framework or as a requirement of interconnecting and operating a generator.
- Recommends that System Black Start Capability become a required ancillary service in the SMD framework.
- Recommends that Energy Imbalance be removed as an ancillary service since it is a measure that allows each generator and load to settle differences between scheduled and actual uses in the real-time market.
- Clarifies that NERC does not set minimum operating reserve requirements.

1. The Relationship Between IOS and Ancillary Services Proposed in the SMD Needs to Be Clarified.

a. There is a Distinction Between IOS and Ancillary Services.

IOS are services (exclusive of basic energy and transmission services) that are required to support the reliable operation of interconnected bulk electric systems. IOS are characterized as the fundamental building blocks or ingredients of reliability that are provided by generators (and loads with the requisite capabilities). IOS are distinguished from ancillary services in several ways. IOS are *physical* services that the *transmission provider acquires from generators* (and qualified loads), then integrates and deploys to meet its requirements for reliable operation of the electric grid. Ancillary services are *commercial* products that a *transmission customer acquires from the transmission provider* (or self-provides) to meet the customer's share of obligations for reliable interconnected grid operations.

b. There are Benefits to Aligning Ancillary Services with IOS.

Because they describe physical ingredients of reliability, IOS have relatively fixed definitions and attributes. Ancillary services, however, are adaptable to meet the needs of a particular market design and do not have to exactly align with IOS. However, there are several benefits when ancillary service products are derived from the fundamental reliability services described by IOS. When based on physical attributes, services become fungible and measurable products;

a transmission provider can know how much of a service each generator is providing and the quality of the service being provided.

Likewise, transmission customers have an opportunity to more actively participate in ancillary services markets when well-understood and measurable commodities underlie the market. When ancillary services closely align with the physical services provided by suppliers, transmission customers can understand what they are paying for and assess whether to self-provide or to choose alternative suppliers. When commercial products have little basis in physical commodities, they appear to the customer as uplift charges with little discernable value or opportunity. The ancillary services markets deriving from Order No. 888, for example, have been meager – the typical response of a customer is "just tell me what I need, give it to me, and send me the bill."

In the IOS Reference Document, NERC defines the physical attributes of IOS needed for reliability and suggests practical measures of those attributes using data that are readily available today. Specific measures of performance not only provide a basis for assuring reliability, but can also provide a means for commercial settlement. NERC recommends that the Commission encourage ITPs to consider IOS definitions and measures when developing their ancillary services definitions and market protocols.

2. Comparison of IOS and Ancillary Services Definitions and Attributes.

The NOPR states that "[t]he ancillary services provided as part of the current pro forma [SMD] tariff will largely remain the same under Network Access Service."[21] This statement and other similar statements understate the improvements proposed in the NOPR for the provision of ancillary services through more robust market approaches than were available in Order No. 888. A careful analysis shows that not all the ancillary services carry forward from Order No. 888 unchanged. In the table below, the definitions provided in the IOS Reference Document are compared with those in the SMD Tariff. NERC requests that the Commission clarify the

[21] NOPR ¶162.

ancillary services definitions in its Final Rule, and in particular note the similarities and differences from Order No. 888 in the comments below.

NERC IOS Definitions	SMD Tariff Definitions	NERC Comments
Regulation: The provision of generation and load response capability, including capacity, energy, and maneuverability, that responds to automatic controls issued by the Balancing Authority.	**Regulation**: The capability of a specific generating unit with appropriate telecommunications, control and response capability to increase or decrease its output in response to a regulating control signal, in accordance with the specifications in the Manuals. Regulation also encompasses regulation and frequency response service i.e. the continuous balancing of Resources (generation and interchange) with Load variations in order to maintain scheduled Interconnection frequency.	The Regulation ancillary service closely aligns with the IOS. Significant improvements are made in the market provision of this service compared to Order 888. The SMD Tariff uses the term Regulation while Regulation and Frequency Response is used in the Preamble. NERC recommends use of the term Regulation, as it is consistent with the IOS Reference Document, regional practices, and common industry terminology.
Load Following: The provision of generation and load response capability, including capacity, energy, and Maneuverability, that is dispatched within a scheduling period by the Balancing Authority.	None.	NERC defines Load Following as balancing resources with demand over a scheduling period. NERC believes that the provision of Load Following can be met through a five-minute real-time balancing market, as described in the NOPR, making a separate ancillary service unnecessary.
Contingency Reserve: The provision of capacity deployed by the Balancing Authority to reduce Area Control Error to meet the Disturbance Control Standard (DCS) and other NERC and Regional Reliability Council contingency requirements. Contingency Reserves are composed of Contingency Reserve–Spinning and	**Operating Reserves**: Generator Capacity that is available to supply Energy, or Load Resources that are available to Curtail Energy usage, in the event of Contingency conditions, which meet the requirements of the ITP. Operating Reserves include Spinning Reserves and Supplemental Reserves.	The NOPR definitions of contingency reserves (spinning and supplemental) are closely aligned with the IOS. Significant improvements are made in the market provision of these services in the NOPR compared to Order No. 888. There is confusion in the NOPR between long-term capacity reserves, replacement or backup reserves, and contingency response reserves.

NERC IOS Definitions	SMD Tariff Definitions	NERC Comments
Contingency Reserve–Supplemental.		This issue is addressed separately in NERC's comments.
Contingency Reserve – Spinning: The portion of Contingency Reserve provided from IOS Resources consisting of: • Generation synchronized to the system and fully available to serve load within T_{DCS} minutes of the contingency event; or Load fully removable from the system within T_{DCS} minutes of the contingency event.	**Spinning Reserves**: Operating Reserves provided by synchronized Resources that can respond immediately to dispatch instructions.	Same comments as for Operating Reserves.
Contingency Reserve – Supplemental: The portion of Contingency Reserve provided from IOS Resources consisting of: • Generation (synchronized or capable of being synchronized to the system) that is fully available to serve load within T_{DCS} minutes of the contingency event; or Load fully removable from the system within T_{DCS} minutes of the contingency event.	**Supplemental Reserves**: Operating Reserves provided by Resources that can be started, synchronized and loaded within a specified time period.	Same comments as for Operating Reserves.
None.	**Energy Imbalance Service:** provided when a difference occurs between the scheduled and the actual delivery of Energy to a Load located within the ITP's Service Area.	Energy imbalance as a mismatch between scheduled and actual uses of transmission (by generators or loads) that is addressed through a market settlement mechanism. NERC recommends removing Energy Imbalance as an ancillary service in the SMD.
Reactive Power Supply from Generation Sources: The provision of reactive capacity, reactive energy,	**Voltage Support Service**: The provision of reactive power support necessary to maintain transmission voltage.	Reactive Supply and Voltage Control from Generation (Voltage Support Service in the SMD Tariff) is unchanged

NERC IOS Definitions	SMD Tariff Definitions	NERC Comments
and responsiveness from IOS Resources, available to control voltages and support operation of the Bulk Electric System.		from Order No. 888 and is consistent with the corresponding NERC IOS.
None.	**Scheduling, System Control, and Dispatch Services:** Required to schedule the purchase, sale and movement of power through, out of, within, or into the ITP's Service Area.	NERC does not identify this service as an IOS because it is an administrative service, not an electrical service. Scheduling, System Control, and Dispatch Services appropriately remains unchanged from Order No. 888. Because this is not an electrical product acquired from generators, this service could either be a part of the basic transmission service or a separate ancillary service.
Frequency Response: The provision of capacity from IOS Resources that deploys automatically to stabilize frequency following a significant and sustained frequency deviation on the interconnection.	None.	NERC recommends that Primary Frequency Response be considered as either a required ancillary service in the SMD framework or a requirement of interconnecting and operating a generator.
System Black Start Capability: The provision of generating equipment that, following a system blackout, is able to: 1) start without an outside electrical supply; and 2) energize a defined portion of the transmission system. This provides an initial startup supply source for other system capacity as one part of a broader restoration process to re-energize the transmission system.	None.	NERC recommends that System Black Start Capability be considered as a required ancillary service in the SMD framework.

3. To Ensure Reliable System Operations, the Proposed Ancillary Services Will Benefit From the Following Changes.

a. Primary Frequency Response

The NOPR defines Regulation and Frequency Response as an ancillary service.[22] However, this service only partially describes the frequency response capabilities needed for reliable grid operations and should be renamed Regulation to be consistent with industry practice. Primary frequency response – the governor response of generators – is a distinct and separate capability that is necessary for bulk electric system reliability. Primary frequency response, combined with the inherent response characteristic of loads, acts immediately and automatically to arrest sudden frequency deviations due to a significant loss of load or generation. This response is particularly important as a first line of defense in a system disturbance resulting in a large frequency excursion or separation of one or more electrical islands from the Interconnection. Frequency Response allows an island to stabilize with energized generation and load, significantly reducing the time required to restore normal conditions.

This service is not addressed in the NOPR's definition of Regulation and Frequency Response, as that service is based on the use of an automatic generation control (AGC) program and regulating pulses sent to the generator. AGC does include a frequency bias component, but is not sufficient alone to arrest a sudden frequency deviation caused by a major disturbance or islanding conditions. Because there is no description of the provision of primary frequency response in the SMD NOPR, it could be presumed that this reliability obligation of generators may be addressed in generator interconnection agreements or operating agreements.[23]

NERC recommends that the Commission clarify whether it intends for governor requirements to be addressed through generator interconnection and operating agreements, or whether they may be provided through a Frequency Response ancillary service. The former would be

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[22] NOPR ¶ 284.

[23] Tariff § 9.3 references participating generator agreements.

appropriate if it is determined that the market would not provide sufficient frequency responsive generation or if the burden of providing such a market would not be justified by the efficiency gains in the longer term by market-based decisions to install, maintain and operate governors. The latter would be appropriate if market efficiencies could be achieved over time while still meeting reliability obligations, by allowing some generators to provide a market-based primary frequency response service. NERC guidelines (Operating Policy 1, Appendix 1C) state that "generators with 10 MW or greater nameplate rating should be equipped with operational governors for frequency response, that the governors should be free to respond to frequency except during temporary outages, that the governor droop should be set to 5%, and that the governors should be fully responsive outside a bandwidth of 0.036 Hertz."

b. System Black Start Capability

The NOPR is silent on the need for system black start capability, as was Order No. 888. The Commission has an opportunity to correct this omission. NERC requires that all electric systems have black start capability – generators that can start from a black condition without an outside power source, and energize transmission facilities, other generators, and loads. In moving to an independent transmission provider as defined in the NOPR, the transmission provider can no longer own the generating resources that can be used for black start and these black start capabilities will have to be provided by the market.

On September 30, 2002, PJM filed amendments to the PJM Open Access Transmission Tariff, proposing to add a new Schedule 6A, Black Start Service.[24] This filing supports the value and need for black start ancillary service in an LMP-based market run by an independent market operator. It should be noted that NERC defines System Black Start Capability as a community service intended to reenergize the grid, other generators, and loads. As such, this service is not a cranking service for an individual load, generator, or select group of transmission users. NERC strongly recommends that the Commission add black start capability to the Final Rule as a required ancillary service.

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[24] Docket No. ER02-2651-000.

c. Energy Imbalance

The NOPR defines Energy Imbalance as a distinct ancillary service, which NERC believes introduces confusion into the discussion of ancillary services.[25] The IOS Reference Document defines Energy Imbalance as a measure of the energy mismatch between a scheduled and actual use of the transmission system (supply or demand). Imbalances can accrue from any mismatch by loads or generators. Load mismatches can stem from forecasting errors or unplanned loss of a resource. Generator mismatches can result from a difference between scheduled or instructed output and actual output. Energy imbalance can even result from the provision of ancillary services – such as over or under-provision of regulation or contingency reserves.

The NOPR supports NERC's conclusion that Energy Imbalance is not a distinct ancillary service by stating "energy imbalance service would be provided through the transmission provider's real-time energy market."[26] The NOPR further states that "the transmission customer would be charged the real-time price of energy for any imbalance, i.e., the difference between the energy the transmission customer schedules a day ahead on the system and the amount that it takes off the system in real time."[27] Energy Imbalance, therefore, is not a distinct ancillary service product to be bought and sold as a commodity in the market, but is rather an integral component of the balancing and settlement process of the real-time market.

Energy Imbalance is also distinguished from the other ancillary services in that it results directly from the transmission use of an individual transmission user and is not a community-based reliability obligation like the other services. Transmission users are required to compensate for their own mismatches. Therefore, NERC recommends that the Commission remove Energy Imbalance from the list of ancillary services.

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[25] NOPR footnote 149.

[26] NOPR ¶ 285, 306, and 320, and Tariff § C.4.

[27] NOPR ¶ 222.

d. Dynamic Transfers

The NOPR states that Regulation must be generated in the ITP's area.[28] However, Regulation obligations can be met by resources from another system and transferred between areas by means of a "dynamic transfer." This is a reliable and accepted practice today that does not need to be limited by SMD. Because the amount of the transfer varies continuously, the use of dynamic transfers does raise a question regarding what transmission service rights are necessary to deliver this dynamic response capability from one system to another, but this question has existed since Order No. 888 was issued. NERC recommends that the Commission delete the requirement that Regulation be generated in the ITP's area and that the Commission address what transmission service rights are necessary for dynamic transfers of Regulation.

e. Shortages of Ancillary Services Resources

The LMP model assumes that sufficient energy, capacity, and IOS will be provided in response to price signals. There may, however, be instances in which the market does not respond sufficiently to meet reliability obligations or in which there is a time lag in the responsiveness that exceeds reliability criteria. In these cases, the ITP must have the authority to require generators to provide the necessary ancillary services, to compensate generators for such services, and to take emergency actions, such as load reduction, if no additional resources are available. While these concepts are alluded to in the NOPR, they are so important to reliability that they warrant special emphasis by the Commission. NERC believes that that the Tariff must be made clear on this point, and that the mutual obligations of the ITPs and the generators must be included in any interconnection agreements.

f. Customer Self-Provision of Ancillary Services

The NOPR's description of customer obligations and options with respect to the procurement or self-provision of ancillary services[29] appears to be reasonable and consistent with IOS concepts,

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[28] Tariff § III.F.5.4(i).

[29] NOPR ¶ 288.

with a few clarifications noted here. It should be clear that a customer's obligation with respect to the amount of an ancillary service to be self-provided is determined by the ITP based on system reliability needs, not based on the consumption of an individual customer. IOS and ancillary services are *community* services that are aggregated and deployed on behalf of all transmission users for the purpose of assuring reliable grid operation. Since the system operator can incorporate the random effects of load and generation diversity, it is logical that the customer's share of the community-based reliability service is less than the burden of an individual customer in nearly all cases. All of the ancillary services defined in the NOPR (as well as all of the NERC IOS) are *community* services except Energy Imbalance. Energy Imbalance is associated with the reliability obligation of an individual load or supplier to follow its scheduled uses. As noted above, NERC recommends dropping Energy Imbalance as a separate ancillary service.

g. Allocation of Ancillary Services Obligations

The NOPR states that the ITP is to allocate the costs of providing each ancillary service to loads (who have not self-provided that service) on a pro rata basis.[30] Although NERC argues above that ancillary services are community services, we also note that reliability will be best served by allocating the ancillary services requirements on a rational basis. This issue is of concern in the following cases:

- Some loads may cause an extraordinary burden on grid reliability performance, such as the effect on the regulating obligation of a balancing area caused by sudden load swings of several hundred MW by a large industrial operation. A strict pro rata allocation of the costs of an ancillary service based on MW load served in this case may be a disincentive for the customer to mitigate the impact of its operations on system reliability performance. In cases where socializing the cost of an ancillary service could have an adverse impact on reliability, the ITP should be allowed to seek alternative cost allocation approaches.

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[30] NOPR ¶ 295 and ¶325.

- Allocating the costs of all ancillary services to loads has an element of logic in that costs allocated elsewhere will eventually (in theory) be passed through to loads in the end. This approach, however, ignores that generators – independent of any load they are supplying – can directly create a need for deployment of an ancillary service. An example is the deployment of operating reserves in response to the loss of a generator. Some generators may trip off more frequently than others, causing an increased burden on reserves. Excluding generators from bearing the cost of ancillary services may create disincentives for good performance by those generators.

- The Commission asks for comments on whether entities that export energy from a system should be charged for ancillary services.[31] For the reasons stated above, NERC believes reliability is best served if those who impose a reliability burden pay a fair portion of that cost. Since suppliers who export energy do place a burden for ancillary services on the source balancing area, there should be a method for allocating those costs to those transactions.

h. Ancillary Services and Product Diversity

The Final Rule should recognize that some reliability requirements can be met through a diversity of market products. For example, the ITP can meet its balancing obligations by combining a diverse portfolio of responsive resources, some slower acting and others faster. Regulation does not have to be a homogonous product. Similarly, a diverse portfolio of operating reserves is used to meet contingency response obligations.

4. NERC Does Not Set Minimum Operating Reserve Requirements; Control Areas Must Maintain Reserves to Meet NERC Control Performance Standards.

The NOPR states that: "The North American Electric Reliability Council and the regional reliability councils set rules regarding the minimum operating reserves that must be maintained by the system operator for reliable operation. The rules are expressed in a formula so that the

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[31] NOPR ¶ 296.

value of the minimum operating reserves changes during the day with load conditions and with the sources of supply. Typically, for a large utility, the minimum operating reserves are in the range of 5 to 8 percent of load, but this can vary significant with changing conditions."[32]

NERC wishes to clarify that it does not set minimum operating reserve requirements. Instead, NERC has implemented three control performance standards (Control Performance Standards 1 and 2, and the Disturbance Control Standard) that control areas today — and balancing authorities in the future — must comply with. Some Regional Councils and reserve sharing groups have established minimum operating reserve levels primarily for contingency reserves to ensure that their control area members can meet NERC's Disturbance Control Standard.

There has been considerable debate on the merits of setting operating reserve requirements in NERC's new reliability standards development process. So far, the "Balance Resources and Demand" standard authorization request does not include a minimum operating reserve requirement, and continues with the three control standards discussed above. NERC expects the balancing authorities to comply with these standards by deploying various IOS, such as regulation and contingency reserves that the LSEs have arranged for by purchasing the corresponding ancillary services from the market operator.

[32] NOPR footnote 228.

D. Resource Adequacy and Planning

NERC strongly supports the Commission's intent and justification for establishing resource adequacy requirements in its proposed standard market design.[33] The NOPR recognizes that long-term resource adequacy is a key component of electric system reliability and correctly defines many aspects of market design that will affect resource adequacy, including the need to address generation, transmission and demand programs in meeting resource adequacy requirements.

NERC addresses adequacy from both the transmission and the generation side. NERC defines *adequacy* as the ability of the bulk electric systems to supply the aggregate electric demand and energy requirements of customers at all times taking into account planned or maintenance outages and unplanned or forced outages of system facilities. This means not only having adequate generation to meet customer demands but also the transmission capability to deliver that generation to customers under a predefined range of system conditions and contingencies.

In this section, NERC:

- Recommends that NERC develop minimum resource adequacy standards and related criteria.
- Finds that the proposed level of resource adequacy will not ensure reliability and recommends that alternatives to a fixed capacity requirement be considered.
- Recommends that data requirements be established to implement resource adequacy and regional planning.
- Recommends that a longer planning horizon is needed to implement a resource adequacy requirement.
- Recommends that a capacity penalty is needed to ensure adequate resources.
- Requests further clarification of the regional planning proposal.

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[33] NOPR ¶ 460-550.

1. NERC Should Develop Minimum Standards for Determining Resource Adequacy.

The NOPR states that "[w]e are also considering in the Final Rule to ask the North American Energy Standards Board (NAESB) to develop more detailed standards for determining whether resources satisfy the resource adequacy requirement, and we seek comments on this approach."[34] Given the inherent reliability-related aspects of this activity, NERC respectfully recommends that NERC should be responsible for developing and defining the minimum reliability criteria for long-term resource adequacy. This effort will include the development of criteria to be considered in translating the resource adequacy standard into appropriate equivalent resource capacity (or reserve) requirements for use by the ITP or load serving entities within each ITP area, and will also include the compliance procedures to be used in determining whether resources satisfy the resource adequacy requirements. Many of the NERC regions already have resource adequacy requirements (also referred to as planning reserves) that have been adopted as reliability requirements. Many state commissions look to these regional requirements to ensure adequacy of electricity supply to the customers they represent.

NERC volunteers to take the initiative on this activity through its new standards development process. NERC's standards process is open to all electric industry participants and can be used to reach consensus on such a reliability standard and its associated criteria by all stakeholders. At the same time, NERC and NAESB have recently agreed to work cooperatively in developing wholesale electric reliability standards and related business practice standards and communications protocols. NERC, NAESB and the RTOs are in discussions about how to best apportion the tasks required to implement the SMD. NERC and NAESB, in conjunction with the RTOs and ITPs, should continue to work together in close cooperation to ensure that the necessary standards for reliability and market practices are developed and implemented in an effective and timely manner. Within this framework, the Commission should continue to rely on NERC for all of the electric reliability standards.

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[34] NOPR ¶ 510.

2. The Proposed Level of Resource Adequacy Will Not Ensure Reliability.

NERC supports the NOPR's proposal to impose a resource adequacy requirement on LSEs.[35] However, a realistic minimum resource adequacy standard should be set for all areas based on a consistent methodology that recognizes differing system characteristics in different regions. This approach will avoid the potential for one system leaning on another. The NOPR's reliance on a fixed percentage reserve margin (e.g., 12 percent or some other value) is overly simplistic and may result in inadequate resource levels in some areas.

As mentioned above, NERC offers to use its standards development process to establish more rational minimum resource adequacy reliability criteria (e.g., probability-based criteria that properly account for both capacity constrained and energy constrained systems) for resource adequacy along with the associated criteria and definitions to be used to translate those criteria into equivalent capacity resource (or reserve) requirements or margins for an ITP area and its LSEs.

Resource adequacy is primarily a function of generation, transmission, and demand program capabilities to meet customer demand. NERC-developed minimum resource adequacy criteria will provide the fallback resource adequacy level if a Regional State Advisory Committee, in conjunction with the appropriate ITPs, is not able to agree on a desired level of resource adequacy for a region or area. Even in this circumstance, appropriate regulatory authorities may still need to resolve important policy issues associated with resource adequacy.

Regional State Advisory Committees and/or ITPs could elect to adopt a higher resource adequacy level than the minimum criteria, but should not be allowed to adopt a lower standard than the minimum necessary to avoid one region or area leaning on another for its reliability requirements. The minimum reliability criteria for resource adequacy should be based on a methodology that addresses in a consistent manner the differing characteristics among the regions or areas, such as customer demands, forecast uncertainty, impact of demand programs, the size and number of generator units and their availability, and capacity purchases and sales.

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[35] NOPR ¶ 492.

The resulting criteria will provide the consistency and common level of resource adequacy among all regions and areas that FERC is seeking in its SMD.

3. Capacity Resources Must Be Deliverable to Customers.

Another critical element of resource adequacy is that the capacity resources must be deliverable to serve customer demands.[36] Plans for capacity requirements must take into account transmission access and deliverability as well as the ability to share capacity reserves. This capacity assistance (support from other regions) is an important element in determining resource adequacy within a region or area. Therefore, LSEs must demonstrate that access to their designated resources is physically feasible and that transmission is or will be available to deliver energy from a generator to the LSE that claims that resource in its resource plan.

The ability of the electric system to function with a minimum or reduced amount of resource requirements has an inherent assumption of reliance on the transmission system to allow generation in other areas to be used as backup resources. It is this sharing through the transmission system that allows a reduction in the resource requirements within a region.

Using the Southwest Power Pool ("SPP") as an example, the following illustrates the effect of relying on an Interconnection for reserve requirement. SPP's deterministic criteria calls for an 18 percent load reserve margin based on the following components: 16% forced outages, 5% de-ratings, 3% for hot weather, -2% for diversity, and -4% for other systems in the Interconnection. That is, the Interconnection was able to provide 4 percent of the required capacity requirements, thereby reducing SPP's internal reserve margin from 22 to 18 percent.

4. Allocating Resource Requirements to LSEs Entities Requires Clarification.

The NOPR suggests that a resource requirement be established in each region or area wherein all LSEs have an obligation to provide a pro rata share of the generating resources required to ensure resource adequacy.[37] NERC agrees with the need for a resource adequacy requirement and the need for LSEs to take on some type of resource requirement obligations. However, the

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[36] NOPR ¶ 331, 506 and 514.

[37] NOPR ¶ 474–484.

discussion in the NOPR suggests a point-to-point deliverability test, with each load serving entity required to demonstrate that its resources can be delivered to its load. This test seems to be counter to the definition of Network Access Service, which by definition eliminates point-to-point service to give all customers access to the entire transmission system and to the generation connected to it.

It is not clear how an LSE would demonstrate, in isolation, the deliverability of its designated generation resources to its load. Such deliverability would have no correlation to the function of the market as it relates to the day-to-day operation of the region. Further, the allocation of needed resources to meet a regional resource requirement that uses a load ratio may not provide the LSE with an adequate level of reliability. Other factors should be taken into account such as the electrical location of the LSE, recognition of transmission constraints that would limit the delivery of resources from outside the LSE area, and the need for some demand pockets to maintain a certain percent of internal resources for local area protection because of transmission constraints.

5. All Market Participants Should Be Required to Provide Data to Regional Planning Entities.

The Commission should require all electric industry participants to provide the Regional Planning Entity with all necessary data to conduct resource adequacy assessments.[38] The Commission also needs to identify the kind of data that will be required from transmission, generation, and load serving entities to perform the necessary resource adequacy and regional planning activities. This data will be needed on an existing and forward-looking basis for five or more years into the future, and includes the physical and operational characteristics of existing and proposed new transmission and generation facilities as well as the characteristics of existing and proposed new demand programs. NERC further recommends that its confidential Generating Availability Data System (GADS) be used to determine generator unit performance and availability to ensure that statistically significant generator performance data is available for use in determining generating resource adequacy requirements.

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[38] Id.

6. LSEs Will Still Need to Designate Resources and Loads

The NOPR states that "[b]ecause we are now proposing a resource adequacy requirement and a regional planning process to meet these requirements, the requirement to designate network resources may no longer be needed. We request comment on whether designating network resources and loads is necessary for Network Access Service, particularly with respect to the information required to performing the integration of resources and loads."[39] NERC believes there is still a need to require the designation of network resources, at least through the transitional period from today's procedures until the SMD is fully implemented. There is additional concern that if resources are not designated, this could result in the double counting of resources across systems. Therefore, the need to require the designation of network resources will likely continue.

7. ITPs Should Not Rely Solely on LSE-Supplied Load Forecasts.

The NOPR discusses demand forecasting as a vital factor in determining resource adequacy.[40] In general, the resource adequacy process requires an ITP to:

> (1) Forecast the future demand for its area. The forecast must, where appropriate, also detail "biddable and interruptible" load where such loads are used to satisfy resource adequacy in addition to generation.
>
> (2) Facilitate determination of an adequate level of future regional resources through a Regional State Advisory Committee.
>
> (3) Assign each LSE in its area a share of the needed future resources based on the ratio of its load to the regional load.

While the NOPR states that ITPs will be responsible for their region's demand forecast,[41] it is unclear if the ITP forecast is simply an aggregation of LSE projections. NERC cautions against simply aggregating LSE-supplied forecasts to construct the ITP regional forecast.

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[39] NOPR ¶ 153.

[40] NOPR ¶ 475-503.

The NOPR states that the ITP must check that resources are not double-counted by different LSEs.[42] In addition, footnote 221 theorizes that LSEs may have an incentive to underestimate their future load if doing so would reduce their share of the ITP resource adequacy requirement. Further, the NOPR discusses approaches for assigning each load's share of the regional resource requirement to particular LSEs.[43]

NERC believes that even if all LSEs made accurate forecasts as of a given date, aggregating LSE-produced forecasts to construct the ITP regional load would still be unreliable. Because both suppliers and customers are expected to constantly vie to better their own financial positions, recurring and frequent changes in the relationships between LSEs and customers are likely. Consequently, LSE forecasts of their aggregate loads are expected to change due to frequent load shifting and customer recontracting. Because the NOPR has already established that an appropriate demand forecast should ensure that each load is counted and counted only once, it is likely that LSE forecasts may not satisfy this requirement during the entire planning horizon. In addition, many LSEs do not forecast specific loads. Instead, they rely on projecting their share of a published forecast of the demand in a defined market. In this kind of planning circumstance, there is no reasonable way for an ITP to *ensure* that the aggregation of LSE forecasts will meet the "counted once, but only once" criterion over the entire planning horizon.

For these reasons, NERC respectfully suggests that aggregating LSE-produced forecasts not be used to derive the ITP regional forecast. Instead, it is recommended that the ITP first produce a forecast of regional *geographic* loads and then match its forecasts with the forecasts of LSEs within its footprint.

8. Long-Term Resource Adequacy Requires a Long-Term Planning Horizon.

Long-term resource adequacy requires a five- to ten-year planning horizon to allow sufficient capacity resources and demand response programs to develop to meet future resource requirements. Sufficient time on the order of five to ten years will be necessary as well for

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[41] NOPR ¶ 485 and 486.

[42] NOPR ¶ 475.

[43] NOPR ¶ 498-99.

critical transmission infrastructure to be built. The NOPR correctly emphasizes that the planning of generation and transmission must be coordinated.[44] Without sufficient time for transmission to be placed in service, the effectiveness of any capacity resource development plans may be delayed and cause resources to be stranded due to transmission system constraints. In addition, without considering these long-term lead times, resource adequacy planning could become a paper exercise with undesired results.

NERC recommends that the planning horizon should be at least five years. Although NERC acknowledges the need for different planning horizons in various regions, five years should be considered the minimum. The planning horizon should be long enough to allow for the development of new resources with their associated transmission, but not so long that planning models become unusable as a result of uncertainties in the underlying assumptions.

FERC should require that an LSE's "resource plan" demonstrate how it will meet its resource requirements in every year of the five-year planning horizon, not just the last year as suggested in the regulatory text.[45] This resource plan should be updated annually and reviewed for compliance by the ITP to ensure appropriate firm capacity commitments have been made for at least the first two or three years of the plan.

NERC agrees with the concept of the adequacy requirement serving as a signal for the development of new generation resources. However, if obligations are established and satisfied too far in advance of a planning period, there must also be a process to re-assess compliance with the resource obligation closer to the operating period. For example, if the LSE includes not yet constructed resources in its plans, some later or follow-on assessment must be performed to determine whether those resources will be available when needed. Similarly, resource performance should be evaluated closer to the operating period to ensure that the committed resources will provide for the appropriate level of adequacy.

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[44] NOPR ¶ 520–525; *Regulatory Text* § 35.37.

[45] *Regulatory Text* § 35.37.

9. The Proposed Enforcement Penalties Will Not Result in Adequate Resources

Standard market design should encourage entities to provide adequate resources. Well-designed markets are preferred to penalty structures for encouraging performance. If needed, market incentives should be developed on a regional basis to meet long-term resource adequacy. However, if incentives cannot be implemented, or become ineffective, penalties or other sanctions should be considered. If the Commission determines that penalties are necessary to ensure resource adequacy, they should not be limited to energy penalties for shortages in the real-time market, but must also include penalties for not meeting planned capacity requirements.

The first type of penalty should be a capacity penalty based on an LSE not meeting resource requirements derived from a regional planning process. For example, an LSE should be required at the beginning of each peak season or year to demonstrate that it has adequate capacity resources (e.g., physical plant owned, under contract, or under construction) to meet its portion of an assigned resource requirement. Each LSE should also be required to demonstrate, at least for two or three years forward into the planning horizon, that it (a) will be able to meet its assigned resource requirement, or (b) has achievable alternatives available to provide such capacity resources within that time horizon.

A second type of penalty should be an energy or spot market penalty, as proposed in the NOPR.[46] This should not be the primary penalty for ensuring compliance with resource adequacy requirements because an LSE that does not meet its planned or resource requirement obligation may or may not encounter an energy or spot market penalty depending on system conditions. Without the planned or capacity requirement penalty, an LSE may be able to skate through several peak seasons or years without ensuring that it has acquired adequate resources. It may also be possible for a small group of LSEs to lean on the system and not get penalized. If a capacity-type penalty is not applied based on capacity being in place for the peak season and committed for the next two or three years, then there will always be an incentive to allow others to provide the resource requirements and resource adequacy as envisioned in the NOPR will not be achieved.

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[46] NOPR ¶ 529.

a. *Standard Market Design Should Not Provide Incentives to Rely on the Short-Term Market for Resource Adequacy Requirements.*

As drafted, the NOPR will create an incentive to rely on short-term markets to provide the needed capacity resources.[47] As the following examples illustrate, the proposed penalties will not be sufficient to ensure long-term resource adequacy.

1) The penalty may be less than the annual cost of owning additional capacity. If the construction cost of a combustion turbine is $350/kW and the annual cost of ownership is 20%, then the annual revenue requirement for one megawatt would be $70,000. Even at a $1000/MWh adder, as proposed in the NOPR, the shortage would need to last 70 hours to be greater than the annual cost of ownership.

2) The penalty applies only to the spot energy purchases, and is not based on the amount of required resources for the entire load serving entity's load to be served. This spot energy penalty combined with the probability that there will not be a shortage would encourage LSEs to lean on the system.

Penalties should be substantial enough to ensure compliance, and not allow an LSE to buy its way around the resource adequacy standard. The penalty should not be based on when, or if, there is a shortage. It should be based on the LSE meeting its defined resource requirements, with firm commitments, for at least the first two or three years of the planning horizon window.

If a shortage occurs where the ITP cannot satisfy demand in the spot market and meet the minimum requirement for operating reserves, the ITP must add a per-megawatt-hour penalty to the price of spot market energy for a load serving entity that did not meet its share of the regional resource requirements for that year.

This approach to a penalty structure creates a situation where the load serving entity will weigh the cost of penalties against the cost of providing resources. The penalty should be high enough

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[47] NOPR ¶ 526.

such that failing to meet the adequacy requirement and paying the penalty is not an acceptable alternative to developing resources. NERC agrees conceptually that the penalty must be high, and is concerned that this constraint or proposed energy penalty will motivate LSEs to take the risk that they will not incur the penalty when they have not met their adequacy requirements.

Finally, the NOPR asks for comment on whether it should allow a liquidated damages contract for power from unspecified sources to be included in the resource adequacy plan.[48] If the Commission allows a liquidated damages contract to fulfill the resource adequacy requirement, then the contract must be backed by designated resources that are verifiable. Otherwise, the requirement to have adequate physical resource facilities over a planning horizon will be undermined and reliability may be adversely impacted. A lawsuit to collect liquidated damages is not a substitute for megawatts and mega-Vars when they are needed to ensure reliability.

b. Selective Load Curtailments Are Not Feasible.

If the ITP must curtail load, the NOPR states that the ITP first curtail spot energy purchases of LSEs that did not meet their resource adequacy requirement.[49] This selective curtailment of an LSE's load is very difficult, if not impossible, to achieve in most cases. This curtailment approach is not currently technically feasible for all LSEs, nor is it consistent with the objectives of real-time operations. Therefore, this approach will not achieve FERC's objective of ensuring that the customers of LSEs that are short of resources will lose service ahead of the customers of entities with adequate resources.

10. A Regional Planning Process is Needed to Ensure Electric System Reliability.

The NOPR recognizes that "competitive and reliable regional power markets require adequate transmission infrastructure" and proposes a Regional Planning Process as a key component of its Standard Market Design.[50] One of the primary roles of NERC and its ten Regional Councils

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[48] NOPR ¶ 513.

[49] NOPR ¶ 472, 477, 529, and 530.

[50] NOPR ¶ 335-50.

has been to facilitate intra- and inter-regional planning efforts in North America through the development of reliability standards, model development, joint studies, and the exchange of information. It is through this historical experience that NERC offers the following comments on the proposed Regional Planning Process.

NERC has also observed the need to improve transmission expansion processes. In its "Transmission Expansion: Issues and Recommendations" document published in February 2002, NERC sought to identify the obstacles that are impacting the planning and expansion of the transmission systems. Issues and recommendations were outlined for the following areas — planning, cost recovery, siting, and education — to help alleviate the obstacles to transmission reinforcement and expansion. NERC encourages the Commission to review and consider these recommendations where applicable when finalizing its Regional Planning Process.

A structured process for regional planning, which is developed and implemented in a timely manner and that strictly enforces NERC reliability standards, should address these issues. The reliability of bulk electric systems must play a prominent role in the analysis and implementation of regional electric infrastructure plans and NERC strongly endorses the Commission's recognition of maintaining reliability as a prerequisite to system modifications.

Although NERC supports the concept of regional planning, it is concerned that the proposed regional planning process lacks sufficient details. NERC assumes that entities in the regions described in paragraphs 341–344 of the NOPR will institute the regional planning process and seeks clarification on the following: Will the process design be left to the individual regions, or will a common process be sought? The identification of regional transmission plans will require a coordinated study effort. Will the scope, assumptions, and methodology for these studies be the same for all regions? The initial effort is to be designed to identify beneficial transmission needed for both reliability and economic reasons. Will the process be expanded to identify generation and demand response plans? In summary, the common purpose of the regional planning process needs to be better defined before it is implemented.

a. Regional Planning Must be Performed in a Non-Discriminatory Manner

From a reliability perspective, it is important that the operating and planning of transmission be performed on a wide-area or regional basis, consistent with NERC reliability standards and applicable regional standards. NERC is concerned that adequate transmission planning be performed in a non-discriminatory manner and that all affected stakeholders are involved in the planning process.

b. Role of Independent Transmission Companies in Regional Planning.

NERC's Functional Model defines those planning and operating functions that must be performed to maintain electric system reliability.[51] It has no preference as to what entities perform these functions, only that they be performed and that reliability is not adversely impacted and can be maintained. NERC recognizes that an ITC may bring benefits to the electric industry through the development of additional transmission infrastructure; however, the conditions under which an ITC can be considered an ITP is a FERC issue.

c. Mexico's Participation in Regional Planning Should Be Recognized.

NERC recognizes the active participation of Canadian entities in developing and implementing reliability standards for North America, and commends the Commission for encouraging Canadian participation in the regional planning process.[52] In this same manner, FERC needs to recognize the participation of Mexico. The Comision Federal de Electricidad (CFE) is a member of WECC. That part of CFE in the northern portion of Baja California Norte, Mexico, has for many years been electrically interconnected with the southern entities of WECC and should also be recognized and encouraged to continue with its active participation in the WECC regional planning process.

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[51] NOPR ¶ 135.

[52] NOPR ¶ 340.

d. The Proposed Regional Planning Timeframe Is Aggressive.

The NOPR proposes that a regional planning process be instituted within six months of the effective date of the Final Rule, and that the first regional transmission plans be completed within twelve months after the effective date of the Final Rule (six months after instituting the process).[53] NERC believes that the proposed timeframe for completing the first regional transmission plans is very aggressive; some entities may be able to comply with FERC's timeline and others may not. NERC recommends that the Commission allow regions to file requests for extensions to submit regional plans for review and approval if they cannot meet the 12-month deadline.

E. Transmission Capacity Analysis and Assessment

In this section, NERC:

- Recommends that ITPs work closely with individual transmission owners to ensure the most accurate calculation of ATC, and clarifies that it has approved planning standards for total transfer capability, available transfer capability, capacity benefits margin, and transmission reserve margin.
- Recommends that any firm transmission rights be based upon appropriate simultaneous feasibility tests in accordance with reliability rules.

1. Independence Will Not Necessarily Ensure More Accurate Calculations of ATC.

The NOPR states that the calculation of Available Transfer Capability (ATC) is a source of discrimination and that instead, an independent entity should calculate ATC.[54] NERC agrees that the use of an independent entity to calculate ATC will presumably eliminate the opportunity for discrimination, but cautions that it will not necessarily ensure a more accurate

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[53] NOPR ¶ 338, 345.

[54] NOPR ¶50-51.

calculation. Even when common data are used and a reasonably well-defined methodology exists, the calculation of ATC may not be performed consistently by multiple parties. However, calculations performed by a single, large, entity such as an ITP will be more consistent over a broader area but may not be more accurate. To ensure maximum accuracy, the ITP must work closely with individual transmission owners because they may have more specific knowledge of their systems, especially for longer-term calculations.

ITPs will need to obtain agreement that consistent assumptions about the inputs are used when calculating ATC, including demand forecasts, power flow models, etc., or else differences will continue to arise. Unless the ITP performs these calculations consistently, ATC calculated for sections of its territory will not necessarily be consistent in the eyes of some market participants. Right now, ATC is being calculated similarly across the United Stated, but the input assumptions vary greatly; this can create the perception that those who calculate ATC are taking advantage of the situation. For example, if one area uses real time demand forecasting, but the rest of the ITP does not have this capability, should the ITP default to a lesser approach? Who will make this decision?

NERC wishes to clarify that it approved planning standards for total transfer capability, available transfer capability, capacity benefits margin, and transmission reserve margin in February 2002.[55] NERC has also completed a review of proposed compliance measures associated with these standards. These planning standards provide a standardized framework under which TTC, ATC, CBM and TRM values must be determined within each Region.[56] It is in the application of the specific requirements and measurements of the standards that each Regional methodology must address where differences arise. Thus, in spite of these efforts towards standardization, there are still differences in how ATC is determined resulting largely from the input assumptions made during the determination process. Until there is a single set of

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[55] NOPR Appendix C. p.16.

[56] NERC's Available Transmission Capability Working Group wrote a white paper on TRM and CBM margins used in ATC calculations. The intent of the paper was to establish a common understanding of TRM and CBM. NERC also published a reference document for calculating ATC. Both of these documents can be found at: http://www.nerc.com/~filez/atcwg.html.

planning criteria for all transmission owners, there will continue to be differences in the contingencies and margins used in ATC calculations.

2. Transmission Capacity Allocations Must Meet NERC Simultaneous Feasibility Tests

The NOPR proposes that all customers take transmission services under the proposed Network Access Service, which allows the flexibility of network integration service and the measure of "re-assignability" similar to that available under firm Point-to-Point Transmission Service.[57] Network Access Service will give all customers the opportunity to have tradable CRRs. As defined, the initial allocation and subsequent allocations of CRRs will be subject to a simultaneous feasibility test.[58] According to the NOPR, simultaneous feasibility "means that power can be simultaneously transmitted from receipt points to the delivery points specified in the CRRs in a contingency-constrained dispatch. If this power flow does not cause overloads on the system (either pre- or post-contingency), then the power flow is simultaneously feasible."[59]

NERC takes no position regarding the methods used to determine the allocation of CRRs. However, simultaneous feasibility studies are essential during the planning and operating horizons to verify that expected transmission uses are within established design and operating criteria, and must be conducted in accordance with the applicable NERC standards.

IV. PART TWO — CYBER-SECURITY STANDARDS

NERC supports the Commission's adoption of cyber-security standards. Wholesale electric grid operations are highly interdependent, and a failure of one part of the generation, transmission or grid management system can compromise the reliable operation of a major portion of the regional grid. Similarly, the wholesale electric market — as a network of

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[57] NOPR ¶ 377.

[58] NOPR ¶ 377.

[59] NOPR footnote 182.

economic transactions and interdependencies — relies on the continuing reliable operation of not only physical grid resources, but also the operational infrastructure of monitoring, dispatch and market software and systems. Because of this mutual vulnerability and interdependence, it is necessary to safeguard the critical cyber assets that support electric grid and wholesale market operations by establishing minimum standards for all those who participate in any way in electric wholesale market operations. Doing so will guard against a lack of cyber security for one critical asset compromising security and risking grid and market failure for the grid or market as a whole.

NERC's Critical Infrastructure Protection Advisory Group ("CIPAG") developed the draft security standards that were included as Appendix G to the Commission's standard market design notice of proposed rulemaking. After reviewing the comments filed in response to the NOPR and based upon further discussion within the industry, the CIPAG is recommending changes to Appendix G. A draft of the revised Appendix G is included with these comments as Attachment A. These comments explain the significant revisions that NERC proposes for Appendix G.

A. Application

NERC recommends removal of the "Application" section from Appendix G and instead including a discussion of the applicability of the standards within the final rule itself. NERC, the CIPAG, and the CIPAG Working Group on SMD Cyber-Security Standards believe it is inappropriate for the standards to specify who may be subject to the standards. We believe this is more properly the responsibility of the Commission. Moreover, unnecessary confusion could result if there are any inadvertent differences between the Commission's definition of entities subject to the standards and any such definition stated within the standards. For that reason, we have removed the "Application" section from the standards and inserted the term "Responsible Entity," which we have defined as those participants in electric wholesale market operations that the Commission requires to comply with the cyber-security standards.

We recognize that the Commission does need to address the issue of who it intends to be subject to the standards. Thus, we suggest inserting the following new paragraph or its equivalent at an appropriate location within the final rule:

> "These standards are intended to ensure that appropriate mitigating plans and actions are in place, recognizing the differing roles of each participant in the wholesale market and the differing risks being managed. Therefore, the cyber-security standards shall apply to any entity filing an SMD Tariff, and all other entities subject to filing a tariff with the Commission, that own or operate relevant systems and equipment as described in the cyber-security standards attached in Appendix G. These entities would be "Responsible Entities" as defined in Appendix G."

B. Compliance

NERC recommends removing the "Compliance" section from Appendix G and instead including a discussion of compliance in the final rule itself. NERC, CIPAG, and the CIPAG Working Group on SMD Cyber-Security Standards believe it is inappropriate for the standards to attempt to define when the standards become effective, as that is clearly set forth in the SMD NOPR and should be included in the final rule as well. Moreover, there are important policy issues regarding initial implementation, notification and enforcement that are more properly the responsibility of the Commission. Therefore, we have removed the "Compliance" section from the standards. However, we believe that the Commission would benefit from the result of our discussion of these important issues.

First, there is serious concern about the timing of the first effective date for these standards. Many companies no longer have the ability to increase their 2003 budget for additional equipment, software, or personnel that may be required in order to implement the standards by January 1, 2004. Second, most participants believed that there should be some process to bring noncompliant entities into compliance before their access to the wholesale market was terminated. This was most critical for the providers of transmission services, who cannot be replaced. There were also questions relating to the possible imposition of unnecessary breaches of contract if a noncompliant wholesale market participant were to immediately lose access to the wholesale market. A related, third, issue arose because wholesale market participants are undergoing rapid and (for the foreseeable future) continuing changes, such as mergers. A new corporate owner may have different cyber-security systems and procedures that may not easily be merged with those of a pre-existing company. Finally, all participants were concerned that self-certification forms that included specific information about particular issues of noncompliance could be released under the Freedom of Information Act (FOIA) or otherwise, thus becoming roadmaps to an attack. NERC also recognizes that the Commission from time to time may need to be able to review sufficient records to determine whether and to what extent there has been noncompliance.

In light of these considerations, NERC suggests inserting the following new paragraphs or their equivalent at an appropriate location within the final rule:

> "The cyber-security standards shall become effective on January 1, 2004. However, the Commission notes that budgets for 2003, for many entities who shall be subject to these standards, have already been finalized. Thus, it is not appropriate to expect more than substantial compliance by January 1, 2004. Entities submitting their first annual self-certification may modify the form attached in Appendix G to reflect that circumstance. However, we do expect complete compliance by January 1, 2005. Further, we expect Responsible Entities to retain sufficient records to allow Commission staff to verify compliance with the cyber-security standards.'
>
> "After January 1, 2005, if a Responsible Entity is at any time unable to certify to complete compliance, it shall immediately contact the Commission to apprise us of the situation and the entity's plans for remediation. We shall treat all vulnerability information gathered during any such communication as confidential business secrets under the Freedom of Information Act. Failure to comply with the cyber-security standards may lead the Commission to impose remediation and/ or monitoring requirements, such as mitigating or compensating controls, that shall ensure compliance as soon as reasonably possible, and by some date certain. Continued noncompliance may lead to more severe Commission action, up to and including loss of direct access to the wholesale market.'
>
> "The Commission recognizes that there may be a material change to the security environment of a Responsible Entity, separate and apart from a failure to comply with the cyber-security standards. This could arise from a major change in corporate structure, such as a merger, or a major change in business operations. In such cases, it may not be possible for a Responsible Entity to file its annual self-certification on January 1 of a particular year. Should such a major change occur, the entity subject to

> the required self-certification shall ask the Commission for an appropriate extension of the upcoming self-certification deadline."

In order to implement the above language, we revised the self-certification form attached to the Cyber-Security Standards. (While some industry participants questioned the level of corporate representative that would be necessary or sufficient to sign the self-certification form, the form does not reflect a change in that respect.) We have also added a record-retention requirement to the standards themselves, at the end of the "Governance" section.

C. Definitions

NERC recommends addition of a Definitions section in Appendix G.

D. Electronic Security Perimeter

CIPAG has prepared the diagrams included as Attachments B-1 and B-2 to these comments to illustrate the concept of an electronic security perimeter. These diagrams are also available on the NERC web site as a PowerPoint file: "Electronic Security Perimeter Diagrams.ppt," at http://www.nerc.com/~filez/cipfiles.html.

E. References

NERC recommends removal of the section "References" from Appendix G and instead including the following comments in the appropriate location in the final rule.

> "The North American Electric Reliability Council (NERC) has established and maintains Security Guidelines for the Electricity Sector. NERC also provides a list of additional sources for security best practices. These references shall be helpful in developing organization-specific security standards and procedures for critical wholesale market resources."

F. Self-Certification Form

NERC recommends changing the heading of the self-certification form at the end of Appendix G from "Annual Self-Certification of Compliance with FERC Security Standards" to "Annual Self-Certification of Compliance with FERC Cyber-Security Standards" as shown in the revised Appendix G.

NERC appreciates the opportunity to provide these comments on the SMD NOPR. We look forward to working with the Commission and the industry to ensure that the reliability and security of the bulk electric systems in North America are maintained as competitive markets evolve.

Respectfully submitted,

NORTH AMERICAN ELECTRIC
RELIABILITY COUNCIL

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November 15, 2002

CERTIFICATE OF SERVICE

I certify that I have caused a copy of this filing to be mailed to each person on the service list for this docket.

David N. Cook

Appendix G
Cyber Security Standards for Electric Wholesale Market Operations Participants
(as revised by NERC CIPAG , November 2002)

PURPOSE

Wholesale electric grid operations are highly interdependent, and a failure of one part of the generation, transmission or grid management system can compromise the reliable operation of a major portion of the regional grid. Similarly, the wholesale electric market — as a network of economic transactions and interdependencies — relies on the continuing reliable operation of not only physical grid resources, but also the operational infrastructure of monitoring, dispatch and market software and systems. Because of this mutual vulnerability and interdependence, it is necessary to safeguard the Critical Cyber Assets that support electric grid and wholesale market operations ("Market Operations") by establishing minimum standards for all those who participate in any way in Electric Wholesale Market Operations ("Responsible Entities"), to assure that a lack of cyber security for one critical asset does not compromise security and risk grid and market failure for the market or grid as a whole.

These standards ensure that Responsible Entities understand their role in market stability, have identified their critical cyber assets related to their key market operations, and have in place an appropriate Security Program. This program should mitigate the impact to Market Operations from acts, either accidental or malicious, that could cause wide-ranging, harmful impacts on Market Operations. A basic Cyber Security Program for Market Operations shall cover governance, planning, prevention, operations, incident response, and business continuity. These standards are intended to ensure that appropriate mitigating plans and actions are in place, recognizing the differing roles of each Responsible Entity and the differing risks being managed.

Cyber Security Standards for Market Operations shall primarily focus on electronic systems, which include hardware, software, data, related communications networks, control systems as they impact the Market Operations, and personnel (hereafter the word cyber shall refer to all of these aspects). In addition, physical security shall be addressed to the extent that it is necessary to assure a secure physical environment for cyber resources.

This initial set of Cyber Security Standards represent a minimum set of measures derived from the NERC Security Guidelines. Responsible Entities are encouraged to review their individual situation and tolerance for risk and implement a Cyber Security Program that goes beyond the basic Cyber Security Standards herein.

DEFINITIONS

Responsible Entities

Those participants in Wholesale Electric Market Operations that the Federal Energy Regulatory Commission has required to comply with these Security Standards.

Critical Cyber Assets

Those computers, software, and communication networks that support, operate, or otherwise interact with the wholesale market operations. This includes assets that can support the Market Operations, such as transmission operations control systems.

Electronic Security Perimeter

The border surrounding the network or group of sub-networks (the "secure network") to which the critical cyber systems are connected. All computer systems connected to the secure network are considered to be within the electronic border (Electronic Security Perimeter) even if they are not defined as critical systems per this standard. Data communications in and out of the secure network are passed through electronic access control points (eg firewalls, routers) to ensure unauthorized data traffic is not passed.

Physical Security Perimeter

Computer rooms, telecommunications rooms, operations centers, and other clearly defined locations in which critical cyber assets are housed and access is controlled.

Authorized Person

Any person who is authorized to pass through a Physical Security Perimeter without escort, or access a critical cyber asset within the Electronic Security Perimeter, for any purpose to include revision to the asset, controlling the Market Operations systems or manipulating information. (Access to a system within the Electronic Security Perimeter may be either from within the Physical Security Perimeter or via an access control point.)

CYBER SECURITY STANDARDS

Governance:

Responsible Entity senior management shall designate a management official to be responsible for establishing and managing a basic Cyber Security Program for electric wholesale market operations and for submitting self-certifications to the FERC.

Information supporting annual self-certification of compliance with these cyber-security standards shall be retained by the Responsible Entity for a period sufficient to permit reasonable review and verification by FERC.

Scope:

Responsible Entities shall define their security perimeters and identify the boundaries and defenses for physical and cyber security that delineate and protect the critical resources under their control. The security perimeters shall identify all entry and exit points and the requirements for access controls.

A Cyber Security Program and policy based on these Cyber Security Standards shall be developed to protect Market Operations. Additionally, related procedures shall be created that guide implementation and enforcement of the Cyber Security Program and policy. The Cyber Security Program, policy, and procedures shall be reviewed for appropriateness (due to changes in personnel, technology, equipment configuration, vulnerabilities and threats) as necessary, and at least annually.

Asset Identification:

Each Responsible Entity shall identify those cyber assets that are critical to the operation of the wholesale market. Those assets shall be afforded a level of security commensurate with their overall criticality.

Access Control:

Procedures shall be in place to identify individual users of critical cyber assets within the security perimeters and their time of access. Personnel, including visitors and service vendors, shall only have access to critical cyber assets within the security perimeters for which they are authorized. Personnel allowed temporary access within the security perimeter shall be escorted at all times.

Procedures for critical electric resources within the cyber security perimeter shall be established to monitor and control physical access in accordance with relevant NERC Security Guidelines.

Critical electric facilities shall restrict the distribution of maps, floor plans and equipment layouts pertaining to those facilities, and restrict the use of signage indicating critical facility locations.

Personnel:

Any person authorized to have access within a secure perimeter shall be trained on the Cyber Security Program and security standards relevant to their respective positions. This training shall start upon employment, be reviewed annually and at career points where significant responsibilities change. Ongoing programs to ensure trustworthiness and reliability of individuals with authorized access to critical cyber systems are required. These programs shall be conducted consistent with applicable laws, human resource practices, and NERC Security Guidelines for Background Investigations.

Systems Management:

Procedures for protecting critical cyber assets within the security perimeter shall address:

1) The use of effective password routines that periodically require changing of passwords, including the replacement of default passwords on newly installed equipment;
2) Authorization and periodic review of computer accounts and physical access rights;
3) Disabling of unauthorized (invalidated, expired) or unused computer accounts and physical access rights;
4) Disabling of unused network services and ports;
5) Secure dial-up modem connections;
6) Firewall software;

7) Intrusion detection processes;

8) Security patch management;

9) Installation and update of anti-virus software checkers;

10) Assurance that telecommunications assets and channels connecting critical cyber assets between electronic security perimeters or with other market participants are secure. (Example: telemetry that is exchanged directly between market operations systems and power plants and substations.)

11) Operator logs, application logs, and intrusion detection logs shall be maintained as appropriate for the purpose of checking system anomalies and for evidence of suspected unauthorized activity.

Planning:

Security requirements for Critical Cyber Assets within the Electronic Security Perimeters shall be identified, documented and agreed upon prior to development, procurement, enhancement to, installation of and acceptance testing for cyber assets or related physical features. For Critical Cyber Assets, this means developing cyber security procedures to augment existing test and/or acceptance procedures.

Development and testing of Critical Cyber Assets shall be conducted in a manner so as to not adversely impact electric and wholesale market operations.

Incident Response:

Responsible Entities shall have incident response procedures, which define roles, responsibilities and actions to rapidly detect and protect critical cyber assets in the event of harmful or unusual incidents, whether accidental or malicious.

Responsible Entities shall report incidents consistent with the Electricity Sector — Information Sharing and Analysis Center Indications, Analysis, and Warning (IAW) Program or local market processes as appropriate.

Business Continuity:

Responsible Entities shall have contingency plans that define roles, responsibilities and actions for protecting the rest of the electric grid and wholesale market from the failure of their own critical resources. Those plans should further define the roles, responsibilities and actions needed to quickly recover or reestablish electric grid and wholesale market functions, processes and systems, in the event that a critical physical or cyber resource fails or suffers harm or attack. Such plans shall be tested or exercised regularly.

Annual Self-Certification of Compliance with FERC Cyber-Security Standards
(Due January 31, 2004, and every January 31st thereafter)

Date: ______________________

Subject: FERC Filing, Annual Self-Certification re: FERC Cyber-Security Standards

From:____(organization name)

____(organization address)

____(organization address)

____(organization address)

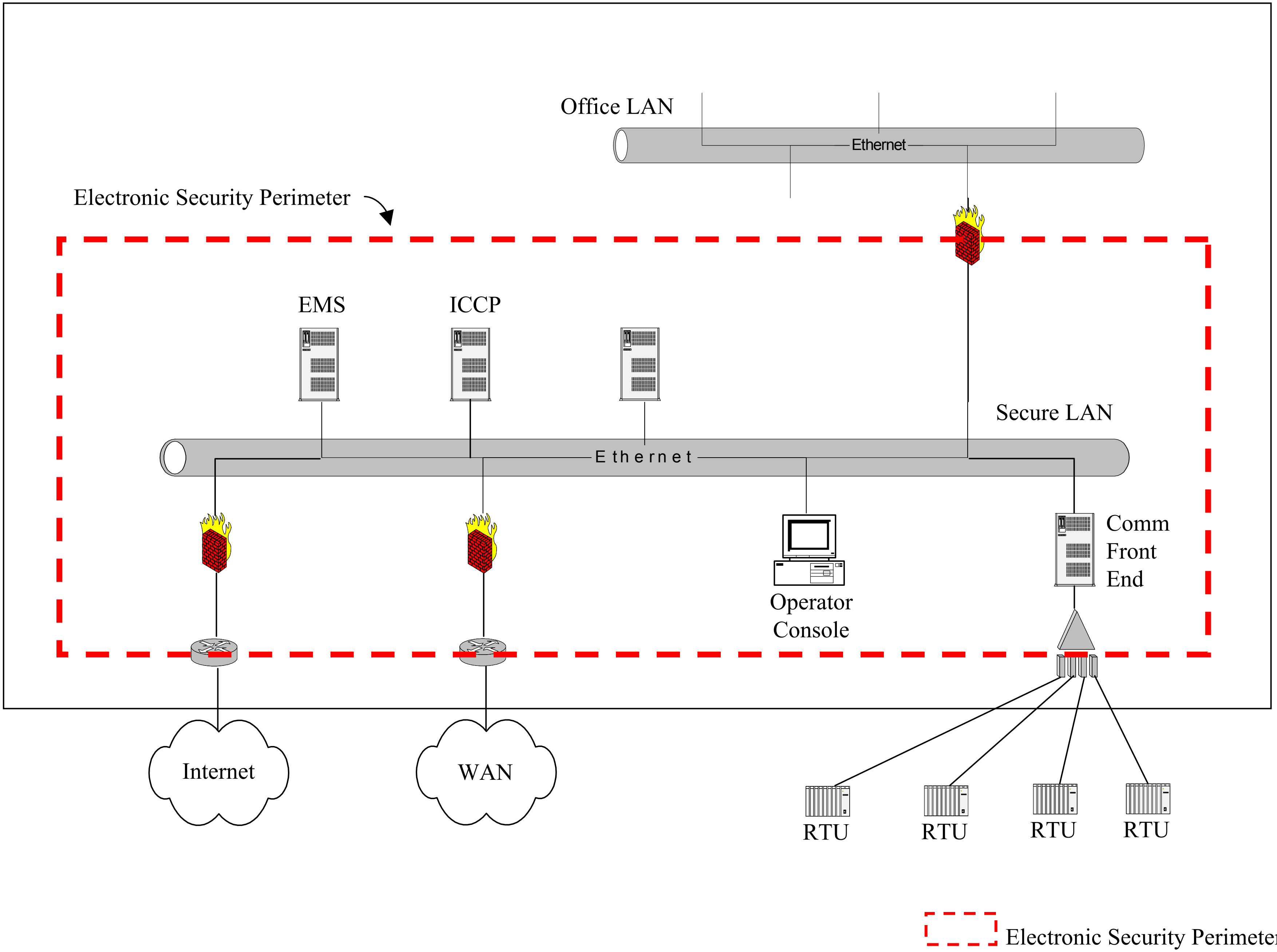
The above-named organization certifies that it complies with the FERC cyber-security standards for the wholesale electric market operations, and maintains records to that effect.

Name:____(print)

____(title)

____(signature)

Attachment B-1



Attachment B-2