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	**)**	

INITIAL COMMENTS OF THE
NEW YORK INDEPENDENT SYSTEM OPERATOR, INC.

The New York Independent System Operator, Inc. ("NYISO") respectfully submits its initial comments on the Commission's Notice of Proposed Rulemaking ("NOPR")[1] in this proceeding.[2] With only those exceptions described herein, we support the NOPR, including the core features of its proposed market design. We have already implemented or will soon introduce systems that are very close to the NOPR's Network Access Transmission Service ("NAS") and Standardized Market Design ("SMD"). As a result, we are able to offer certain insights gained through our own experience.

The NYISO is also co-sponsoring the *Joint Comments of RTO/ISO Group* ("*Joint Comments*") and supports the comments of ISO New England Inc. ("ISO-NE"). The NYISO and ISO-NE have filed a Joint Petition for Declaratory Order ("Joint Petition") concerning the

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[1] *Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design*, Notice of Proposed Rulemaking, FERC Stats. & Regs. ¶ 32,539 (2002); *Notice Revising Public Comment Schedule and Announcing Technical Conferences*, Docket No. RM01-12-000 (September 10, 2002); *Notice of Conferences and Revisions to Public Comment Schedule*, Docket No. RM01-12-000 (October 2, 2002).

[2] Consistent with the Commission's October 2 Notice, the NYISO will submit its initial comments on transmission expansion and pricing, the regional planning process (including merchant transmission project issues), and resource adequacy until January 10, 2003.

formation of a Northeastern Regional Transmission Organization ("NERTO").[3] Finally, the NYISO generally supports the *Initial Comments of John D. Chandley and William W. Hogan*[4] in this proceeding.

We held several meetings with our stakeholders to discuss SMD-related issues. We also provided a draft copy of these comments to stakeholders and incorporated a number of their suggestions. While there is stakeholder support for this filing, it is made on behalf of the NYISO's Board of Directors and management; stakeholders have reserved the right to file comments of their own.

I. EXECUTIVE SUMMARY

The NYISO supports the NOPR in almost all important respects and urges the Commission to proceed with SMD implementation. SMD will bring many benefits. NAS, Locational Marginal Pricing ("LMP"), and Congestion Revenue Rights ("CRRs") will result in a more flexible transmission service that utilizes more fully existing grid capacity. Bid-based, security constrained day-ahead and real-time electricity spot markets that are simultaneously co-optimized with bid-based ancillary services markets will allow efficient wholesale markets. Supporting bilateral contracts will permit market participants to define their own economic relationships and manage risks without being forced to resort to spot markets. Standardizing the market designs in different areas will eliminate many seams and promote the formation of larger electricity markets, regardless of where Independent Transmission Provider ("ITP") boundaries are drawn. In short, the Commission's transmission and market proposals should result in

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3 *Joint Petition for Declaratory Order Regarding the Creation of a Northeastern Regional Transmission Organization,* RT02-3-000 (August 23, 2002).

4 *See Initial Comments of John D. Chandley and William W. Hogan on the Standard Market Design NOPR,* Docket No. RM01-12-000 (November 11, 2002).

efficient price signals, rational infrastructure development incentives and ultimate consumer savings. While we point out areas of the NOPR with which we disagree, the Commission should note that such disagreements are the exceptions to a scheme that we believe is constructive and designed to bring significant national benefits.

We do not agree with the NOPR's proposed governance rules. We believe they are at variance with the principle that grid operators must be independent from market participants and accountable solely to the Commission.[5] They should be revised. The Commission should also withdraw several overly prescriptive proposals that would undermine the efficiency and effectiveness of ITP governance. We are proposing a number of changes[6] and recommending that they be included in the final rule. Accepting these recommendations will ensure that ITP Boards are fully independent. It would also permit the proposed NERTO to be created in a manner consistent with the independent and carefully considered determinations of the NYISO and ISO-NE Boards of Directors.

The Commission should also ensure that the North American Energy Standards Board's ("NAESB") procedures for establishing standardized market and reliability practices do not compromise ITP independence. There is a risk that stakeholders might write procedures that would undermine ITPs' authority to develop market rules. The Commission can prevent this by insisting that ISOs, RTOs and ITPs be heard within the process and by paying close attention to

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[5] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, *Order No. 888*, FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh'g*, *Order No. 888-A*, FERC Stats. & Regs. ¶ 31,048 (1997), *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in part, remanded in part sub nom. Transmission Access Policy Study Group, et al. v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 122 S. Ct. 1012 (2002).

[6] *See* Section XIII.

their concerns about proposed standards, even when they have substantial stakeholder support.[7] Existing ISOs and RTOs are already discussing these issues with NAESB. The Commission could help to advance the discussions by clearly signaling that ISOs, RTOs and ITPs will play an important part in the standard-setting process.

The NYISO agrees with the NOPR's assertion that for-profit Independent Transmission Companies ("ITCs") can make important contributions, especially in the transmission expansion area. However, the NYISO does not agree that the allocation of transmission-related functions that the Commission has provisionally approved for the Midwest should be made a national standard. The Midwest's division of functions may be appropriate for a pre-SMD environment, but is not consistent with an ITP's expanded role under SMD. In addition, because ITCs will be market participants, it would not be appropriate for them to assume market administration functions.[8]

With respect to market design, the NOPR generally prescribes the right degree of helpful standardization of region-specific features. We have, however, identified a few proposals that require unnecessary standardization and ask that the Commission reconsider them.[9] In particular, the Commission should not require existing ISOs or RTOs to revisit previously approved CRR allocations, embedded cost recovery methodologies, rate settlements, policies on the treatment of grandfathered contracts, or license plate rate arrangements. These are issues that neighboring regions can address differently without creating interregional seams. Existing regional solutions to these problems were usually achieved through extensive negotiations.

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[7] *See* Section III.

[8] *See* Section IV.

[9] *See* Section VII.

Undoing them would likely engender controversy and litigation that could delay realization of SMD's benefits.

The final SMD rule should also provide that independent market design decisions made by existing ISOs or RTOs, and future ITPs, should be respected if they are consistent with SMD principles and do not result in the creation of seams. There are many rules, for example, those governing "lumpy" generators, bidding by energy limited resources, uninstructed deviations from real-time schedules, "administrative" demand response programs, and market power mitigation rules,[10] that should be allowed to vary to reflect regional differences.[11] The final rule should also permit ITPs to experiment with new rules that have the potential to improve on today's best practices. Allowing individual ITPs to evolve their own solutions will permit innovation and leave the Commission and the ITPs free to judge the merits of possible market enhancements.

The final rule should also soften or eliminate the NOPR's presumption that all transmission facilities that do not perform a purely local distribution function must be under ITP control. Several ISOs or RTOs have successfully provided NAS-like service and administered SMD-like markets for several years. It is not clear whether they would satisfy this test. This suggests that the NOPR's proposal is more expansive than necessary. Moreover, the identity of the transmission facilities under the control of existing ISOs or RTOs often reflects extensive negotiations with regional transmission owners who believe there are important operational or reliability reasons to retain control over certain facilities. The requirement that these owners

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10 *See* Section VIII.

11 As the Commission is aware, there may be a greater need for such variations in regions that do not already have SMD, or that have system characteristics that differ significantly from the Northeast's.

relinquish control over these facilities could create unnecessary and unproductive controversy and litigation.

The NOPR proposes a number of market design elements that are not part of any existing market design. Some of them would be difficult to implement in the near-term given existing technology, would bring relatively minor benefits, and consume resources that would be better used to support more important enhancements. They include: (i) allowing customers to specify the maximum transmission usage charges and maximum congestion charges they are willing to pay; (ii) allowing customers to specify the maximum total multi-hour block transaction price they are willing to pay; and (iii) multi-part load bidding.[12] We recognize that these features have value to many market participants, so the Commission should either make the implementation of these features optional or give ITPs additional time to implement them.

Several other NOPR proposals seek to replicate elements of the Order No. 888 physical transmission reservation model that are not needed under a financial reservation system. These include the proposals that CRR holders receive a physical curtailment priority, that customers be allowed to submit CRR reconfigurations on "demand," and the emphasis on physical self-supply of ancillary services.[13] These vestigial proposals are not needed, and would create problems under SMD. They should not be included in the final rule.

Beyond market design, the NOPR is correct to focus on consumer protection, the prevention of gaming and protection from the exercise of market power. The NYISO's experience demonstrates that these are important and very challenging issues that require a careful balancing of the need to prevent market abuse against the need to allow legitimate price

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12 *See* Section VIII.

13 *See* Section VIII.

signals (especially during scarcity conditions). The Commission should allow each ITP and market monitoring unit to develop rules that strike the right balance for each region.

We support the NOPR's definition of market power, which recognizes that even short-lived market power can have serious consequences in electricity markets. We also generally support the NOPR's market power monitoring and market power mitigation proposals. The final rule should clarify that the system of "participating generator agreements" proposed in the NOPR is compatible with the NYISO's existing comprehensive mitigation rules.[14] We believe that our system of bid-based conduct and impact mitigation screens is fundamentally the same as the mitigation model proposed in the NOPR, although we do not currently use individual agreements as the vehicles for implementing it.

The final rule should also correct the NOPR's description of automated mitigation procedures as a "temporary" device. "Automated mitigation" is not a separate mitigation mechanism. It is simply a tool for making other mitigation measures operate more efficiently and should be available at any time to market monitoring units that conclude that automation would be helpful.

The NYISO supports the NOPR's proposal on the use of "damage control" bid caps, including the need to gradually move away from caps as demand response mechanisms become more effective. The final rule should not, however, require MMUs to demonstrate that mitigation measures, including bid caps, are necessary in regions where the need has already been proven. Instead the burden should be on those who would have the Commission eliminate mitigation before a market monitoring unit concludes that their removal would be appropriate.

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[14] The NYISO is not proposing, however, that its mitigation systems become a mandatory national model. Regions that have a greater capacity surplus, and less congestion than New York may not need the same degree of mitigation.

With respect to the structure of market monitoring units, the final rule should reaffirm that market monitoring units may report to and be selected by ITP Boards. The Commission should also clarify that ITPs may retain staff to perform administrative market monitoring functions that complement the market monitoring unit's activities.[15]

While we support the NOPR's proposal to adopt standardized market monitoring methodologies, we caution that the Commission not become overly prescriptive or require monitors to apply unnecessary metrics. The Commission's early initiatives in this area appear to be heading in that direction, and we believe they should be reconsidered.

The Commission should also make it clear that monitors must assess the behavior of all market participant sectors. To the extent that there are penalties for gaming or for market power abuses, they should likewise be applicable to all market participants. Any penalties must also be narrowly tailored to avoid punishing legitimate activities.

We support the NOPR's proposal to establish Regional State Advisory Committees. State regulatory commissions should continue to play an important role in electricity markets. Establishing regional committees will ensure that their voices are heard and make it easier for them to perform their own regulatory functions effectively. The Commission should, however, resist pressure to allow states to regulate ITPs or share regulatory functions that are exclusively within the Commission's bailiwick. States' interests will not always be the same as the Commission's. Subjecting ITPs to overlapping and occasionally conflicting federal and state regulation could result in the creation of a regulatory "crazy quilt" that undermines part of the policy underlying the Federal Power Act.

[15] *See* Section IX.

The final rule should also afford all ITPs at least as much protection against liability as was recently conferred upon the Midwest ISO. Not-for profit ITPs that do not own transmission assets will be uniquely vulnerable to liability claims because they will not have "deep pockets." They will generally not enjoy the same state level liability protections as traditional utilities and therefore need strong federal protection.[16]

The final rule should not adopt the standard SMD implementation timetable proposed in the NOPR. The proposed date is no longer reasonable given the considerable delay in the issuance of a final rule. Also the original deadline was probably always too optimistic. Even regions such as New York, that are already very close to SMD, would find it difficult or impossible to implement all of the NOPR's proposed features in the time allowed.[17] Regions that do not have a history of tight power pool operations, and have not already laid the groundwork for regional markets, will almost certainly need even more time to reach the goal. Thus, instead of insisting on a uniform national deadline, the Commission should allow each ITP to propose a SMD implementation timetable in consultation with its stakeholders. The Commission should take a somewhat more practical view of what can be accomplished given existing hardware and software capabilities.

Finally, the SMD rule should of course establish a rebuttable presumption that existing ISOs and RTOs will be the preferred choice to become ITPs for their regions. Absent such a presumption, some market participants might threaten the independence of ISOs or RTOs by

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16 *See* Section X.

17 It is therefore overly optimistic to suggest that the Northeastern ISOs should implement SMD sooner than the NOPR's deadline. *See, e.g., PJM Interconnection , L.L.C.,* 101 FERC ¶ 61,115 at P 14 (2002).

refusing to support their efforts to become ITPs unless they first agreed to make concessions on policy issues. This would be inappropriate and inefficient.

II. THE NYISO SUPPORTS THE NOPR

The NYISO supports the NOPR in almost all respects, including its key features: the use of a voluntary bid-based security constrained dispatch; LMP;[18] NAS;[19] CRRs,[20] multi-settlement energy markets and simultaneously co-optimized ancillary services markets. All of these SMD features were first implemented by the NYISO in 1999 and have brought significant benefits to New York consumers. Certain SMD features, such as nodal pricing for loads and multi-settlement ancillary services markets, are not yet part of the NYISO market design. The NYISO expects to adopt these features when it implements its new Real-Time Scheduling ("RTS") (or "SMD 2.0") software in early 2004.[21] These enhancements will bring the NYISO into complete accord with the Commission's SMD policies sooner than any other market operator.

The NYISO recognizes that some parts of the NOPR have been controversial in different sections of the country. The Commission has wisely begun to address these concerns by

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18 The NYISO's existing locational-based marginal pricing ("LBMP") system is essentially the same as the LMP model outlined in the NOPR. For ease of reference, these comments use the term "LMP" to refer to both LMP and LBMP.

19 The NYISO currently provides transmission service through an implicit, financially-based reservation system that is similar to NAS.

20 The NYISO's existing system of Transmission Congestion Contracts ("TCCs") is essentially the same as the CRR model outlined in the NOPR. For ease of reference, these comments refer solely to CRRs.

21 The RTS project will replace the NYISO's existing real-time scheduling and market software, which is based on older legacy systems, with state-of-the-art software that satisfies the proposed SMD standards. Among other benefits, RTS will eliminate the need for the NYISO to conduct a separate Balancing Market Evaluation ("BME") by incorporating all necessary BME functions into an enhanced security constrained dispatch program. This will improve price convergence between the NYISO's day-ahead and real-time energy markets. It will also bring the NYISO market even closer to the SMD proposal.

signaling[22] that it will respect regional differences in the final SMD rule. It should continue working to build greater support for the NOPR.

At the same time, the Commission should not surrender its leadership role or stop championing SMD's benefits. SMD has been very successful in the Northeast. Its financial approach to transmission reservations has enabled ISOs to provide non-discriminatory open-access transmission service in a manner that maximizes the use of available grid capacity and addresses congestion more accurately than is possible under Order No. 888. Experience in the Northeast, and throughout the world,[23] also confirms that SMD-type systems are the best foundation for truly efficient and open wholesale electricity markets. Adopting SMD, even with allowances for legitimate regional variations, will reduce the number of inter-regional seams and encourage the formation of larger and more efficient markets.

There is every reason to anticipate that SMD's performance in the Northeast will only improve in the future. Both the ISOs and market participants now have substantial experience with SMD and have worked together to correct design flaws that created problems at the

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22 *See, e.g., Cleco Power LLC, et al.,* 101 FERC¶ 61,008 at P2 (2002) and *Arizona Public Service Co., et al.,* 101 FERC ¶ 61,033 at P 4 (2002). "[B]ecause of the extensive efforts committed by industry participants to developing a framework for a sound RTO proposal here, we take this opportunity to clarify that it is not this Commission's intent to overturn, in the final Standard Market Design rule, decisions that are made in this docket. In other words, unless the Commission has specifically indicated in this order that an element of the RTO proposal is inconsistent with the Standard Market Design proposal or needs further work in light of the Standard Market Design proposal, we do not intend, in the final Standard Market Design rule, to revisit prior approvals or acceptances of RTO provisions because of possible inconsistencies with the details of the final rule."

23 *See Initial Comments of John D. Chandley and William W. Hogan on the Standard Market Design NOPR,* Docket No. RM01-12-000 (November 11, 2002) at 63. Chandley and Hogan discuss the widespread use of SMD-type systems around the world. They distinguish the monopolistic transmission owner-operator models in New Zealand and the United Kingdom and note that these are both "incompatible with and inferior to, the Commission's SMD framework in supporting the principles of open access and non-discrimination."

inception of the New York and PJM markets. The Northeastern SMD model will produce the efficient price signals that are necessary for rational infrastructure development and siting decisions. It will also facilitate the creation of effective market-based demand response mechanisms. By ensuring non-discriminatory open-access, supporting markets, promoting new infrastructure construction and fostering demand response, SMD should ultimately achieve the Commission's primary goal of lowering prices for consumers.

SMD can work well in other regions, assuming that appropriate allowances are made for legitimate regional variations.[24] The NYISO's past success in detecting and fixing early SMD flaws should provide guidance that will allow other regions to move to SMD more smoothly. The Commission must not, however, underestimate the difficulty of the process or the amount of time it will take to transition from an Order No. 888 to a SMD-based regime. The Commission must be patient and flexible in accommodating each region's needs. It should not insist on absolute standardization on issues, *e.g.,* CRR allocation rules or the treatment to be afforded to grandfathered contracts, where it is not necessary.

III. INTRODUCTORY SECTIONS (PP 1 - 131)

A. The North American Energy Standards Board (P 116)[25]

The NOPR states that the Wholesale Electric Quadrant of the NAESB will produce business practice and electronic communication standards for the electric utility industry, with ITPs advising NAESB as it develops the standards. NAESB should be required to incorporate ITP guidance into the standards it establishes.

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24 The NYISO believes that relatively few regional variations will be needed in the Northeast, outside of unusual sub-regions such as New York City. The NYISO takes no position on what regional variations will be necessary outside of New York.

25 In addition to the views expressed herein, the NYISO also supports the position of the *Joint Comments* on these issues.

NAESB will be run by stakeholders that have direct business interests in the standards they will be creating. Under SMD, ITPs will be required to implement those standards, but will not have a formal role in NAESB's decision-making process. This is incongruous given the importance of ITP independence from stakeholders and ITPs' authority to make unilateral tariff filings.[26] When the Commission evaluates proposed NAESB standards, it should give careful consideration to ITP (or ISO and RTO) comments even when they are at odds with a stakeholder consensus. While the NYISO is encouraged by recent indications that the Commission expects ISOs, RTOs, and ITPs to play a strong role in standards development, the Commission should commit to this policy by including it in the final rule. This will provide helpful guidance for NAESB which has no experience accommodating ITP-like entities in the natural gas industry.

The Commission should also clarify the relationship between the NAESB process and individual ITP stakeholder processes. The NAESB process should enhance ISO, RTO, and ITP efforts to comply with SMD requirements. NAESB should not be permitted to impede or veto these efforts.

B. The Interim SMD Tariff Filing (PP 121 - 123)

The NOPR proposes that "public utilities" must file tariff revisions by July 31, 2003, to reflect several important Commission orders clarifying the scope of roll-over rights and rights of first refusal under Order No. 888. The final rule should exempt from this requirement those ISOs that already provide financially-based transmission service because the Commission's precedents apply to physical reservation models, not financial systems. Exemptions are even

[26] *See* NOPR at PP 125, 128-129.

more appropriate in the case of ISOs that have already addressed contract roll-over issues within the framework of a financial reservation system.[27]

IV. INDEPENDENT TRANSMISSION COMPANIES (PP 132 - 135)

A. The *TRANSLink* Allocation of ITP Functions Should Not Be The National Standard

The NYISO agrees that for-profit ITCs can bring significant benefits, particularly by facilitating new infrastructure construction and increasing system transfer capability.[28] The allocation of functions between ISOs and ITCs that the Commission adopted in *TRANSLink,*[29]however, should not become the national standard. The *TRANSLink* approach may be appropriate for the Midwest, which has not yet instituted SMD, but is not appropriate for SMD markets. Under SMD there must be a single entity, the ITP, with clear authority to operate the grid and to administer markets.

The *Translink* allocation is incompatible with SMD markets because such markets require a single operator to manage simultaneously the transmission system and administer wholesale energy markets in real-time. SMD uses the same bid-based mechanism to determine both the real-time grid dispatch and market clearing prices. Dispatching, managing congestion, settling load and generation imbalances, simultaneously co-optimizing energy and ancillary services, and operating the transmission system in light of reliability limits are integrated

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27 *See, e.g.,* Attachments K, "Reservation of Certain Transmission Capacity and LBMP Transition Period," and L, "Existing Transmission Agreements & Existing Transmission Capacity for Native Load Tables," of the NYISO's Commission-approved Open Access Transmission Tariff.

28 *See* NOPR at P 132.

29 *TRANSLink Transmission Co. LLC, et al.*, 99 FERC ¶ 61,106 (2002).

functions that cannot be divided among multiple entities. As the original architect of LMP has written, it is a "fallacy" to conclude that core SMD functions can be "sliced and diced."[30]

Each ITP should instead be permitted to work with ITC proponents and negotiate an allocation of functions that accounts for SMD's requirements and region-specific needs. The Joint Petition proposes a NERTO-ITC framework that satisfies these criteria.[31] The Commission could establish basic principles to guide the development of successful ISO-ITC arrangements, but should not mandate a particular allocation of functions.

TRANSLink recognized that the Midwest ISO ("MISO") would need to reassess the division of functions after it implemented SMD.[32] *TRANSLink* also acknowledged that "the security-constrained, economic dispatch needed for an efficient and reliable market is best operated by an independent regional transmission provider" and that "centralized RTO oversight" over an ITC is essential.[33] Nevertheless, *TRANSLink* allowed ITCs to assume functions that the Commission believes had "predominantly local characteristics." A number of these functions may once have been "local" in character, but will become regional functions when SMD is in place, and thus should be handled by ITPs alone.[34]

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30 *See Electricity Market Design and Structure: Avoiding the Separation Fallacy*, Comments of William W. Hogan, Docket No. RM01-12-000 (March 12, 2002).

31 *Joint Petition for Declaratory Order Regarding the Creation of a Northeastern Regional Transmission Organization,* RT02-3-000 (August 23, 2002) at PP 57-58.

32 *TRANSLink* at n. 37. *See also* [April 24 FERC Transcript] at 130 (Commissioner Massey: "I take note of PJM's comments on this matter, they say that the functional operation of the grid must be the responsibility of the entity that is running the locational marginal pricing-based markets and that those functions cannot be separated out or there will be chaos. Frankly, this makes a lot of sense to me.").

33 *TRANSLink* at 61,463.

34 The NYISO is aware that the Commission has permitted several former Alliance RTO members to join PJM through an ITC arrangement modeled after *TRANSLink*. *Alliance Companies, et al.,* 100 FERC ¶ 61,137 at P 43 (2002). This does not mean that the *TRANSLink*
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For example, *TRANSLink* would permit an ITC to submit schedules for,[35] and make rate filings associated with,[36] transactions that "source and sink" within its geographic footprint. These rules cannot be adapted for use in NAS/LMP markets where physical "Point-to-Point Transmission Service" is not offered and transmission is inherently regional in nature.[37] The Commission recognized in *TRANSLink* that once an LMP market is established there is "little opportunity for ITCs to segment the region with alternative congestion management systems. The LMP market not only needs to be uniform, but also operated as a single market."[38] Thus, under SMD, an ITC's congestion management role must be limited.

B. <u>ITCs Should Not Be Allowed to Qualify as ITPs (P 135)</u>

The Commission seeks comment on whether an ITC that has no ties to other market participants would be sufficiently independent to qualify as an ITP. The NYISO believes that ITCs should not be ITPs, because they will be market participants themselves. ITCs would have

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allocation is compatible with SMD. PJM was required to accept *TRANSLink'*s terms because the Commission hoped to promote the establishment of two ITCs that would help to mitigate seams between PJM and the MISO. The arrangement was arguably necessary because PJM and the MISO will have different market designs for the next few years. It is clearly not necessary in regions, like the Northeast, where New York and New England will soon have similar SMD markets. PJM itself was not required to adopt the *Translink* allocation in its original territory, where SMD markets are in place. PJM and the MISO will also be allowed to revisit *TRANSLink's* allocation once they have implemented their "joint and common" market.

35 *Id.* at 61,461-62.

36 *Id.* at 61,465.

37 *TRANSLink* recognized that this might be the case. *Id.* at 61,462 ("Some of the operational control allowed at this time is permitted because it is consistent with today's markets in the Midwest ISO . . . . As we move toward our plan for [SMD] . . . , some of these operational elements may have to be modified.") *See also [4/24 Transcript at 129]* (Commissioner Massey: "I don't understand within a standard market design regime which we're moving to how the scheduling functions can be shared within a region. I am concerned that such a sharing isn't consistent with standard market design.").

38 *Id.* at 61,469.

an incentive to favor their own interests if they were to assume an ITP's operational and planning roles.[39] Although the NOPR suggests that transmission discrimination might not occur because new transmission generally cannot be built quickly, the reality is that subtle opportunities for abuse would continue to exist. For example, the NOPR proposes that ITPs administer a regional planning mechanism that would not artificially favor transmission, generation or demand response solutions.[40] It will be difficult for an ITC with a vested interest in transmission development to satisfy this requirement.[41]

More importantly, an ITC could not fulfill the fundamental ITP responsibility to administer energy markets impartially. ITCs will own transmission facilities, hold CRRs, and compete with other market participants for business opportunities and profits. Allowing them to operate LMP spot markets that manage congestion and define the value of transmission and CRRs could create a significantly unfair advantage. Giving an ITC full access to sensitive bid and cost information submitted by its competitors would likewise provide it with an important competitive edge. At a minimum, ITCs that operate markets would require intense regulatory oversight and strict codes of conduct in order to avoid abuses. Even with these measures, market participants could never be sure that subtle abuses were not going undetected. The Commission should therefore clarify that ITCs should not be ITPs.

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[39] NOPR at P 135.

[40] NOPR at P 347.

[41] Commission precedent clearly establishes that the mere perception that a grid or market operator is not fully independent can be just as harmful as an actual lack of independence. *See, e.g., Order No. 2000* at 31,065, 31,070.

V. THE NEW TRANSMISSION SERVICE (PP 136 – 164)

A. General Comments

NAS represents a significant improvement over Order No. 888's physical reservation open-access regime because it is compatible with SMD's adoption of LMP and allows for a more efficient, flexible and complete utilization of the grid. The NYISO has provided NAS-like financial transmission reservations within its boundaries, coupled with a system of financial congestion hedging rights, for several years. After some early implementation problems were resolved, the NYISO's system has worked well and provides the benefits that the NOPR predicts NAS will bring.

The NYISO therefore fully supports the adoption of NAS, CRRs, and LMP. ITPs that adopt NAS should also administer voluntary spot energy markets to manage congestion, handle imbalances, and facilitate the procurement of ancillary services.[42] NAS can accommodate both short and long-term bilateral transactions. It will also provide transmission customers with a level of service certainty comparable, or superior, to firm transmission service under Order No. 888.[43]

The NOPR states that a separate non-firm transmission service option is not necessary under SMD because customers will be allowed to place a limit on the amount of congestion that they are willing to pay.[44] The NYISO has some concerns about the NOPR's current "up to" congestion bidding proposals, which are discussed below in Section VIII.B. Nevertheless, even if the scope of "up to" congestion bidding is narrowed in the final SMD rule, there is no need to

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42 *See* NOPR at P 138.

43 *See* NOPR at P 144.

44 *See* NOPR at P 145.

provide for a separate non-firm service. In the NYISO system, customers that are unwilling to pay any congestion charges are effectively treated as "non-firm."[45] A similar rule should be included in SMD.

B. Designating Resources and Loads (PP 152 – 153)

The NOPR suggests that Order No. 888's requirement to designate network resources in order to receive transmission service may not be needed under NAS. The NYISO agrees. It is not necessary to "designate" resources and loads under the NYISO market design and it should not be necessary under SMD. The combination of LMP, which provides for continuous redispatching, and CRRs, which provide a financial certainty, obviates the need for requiring resources and loads to be paired.

The NOPR also asks questions about how much information must be included in transmission service applications and whether separate application procedures are needed for marketers that do not serve load or own generation and Load-Serving Entities ("LSEs").[46] Based on its experience, the NYISO believes that ITPs will only need to know: (i) the customer's identity and contact information (including the identity of entities authorized to submit bids on the customer's behalf); (ii) the service term and commencement date; (iii) the requested receipt and delivery points; and (iv) any special customer-specific bidding restrictions that may be in effect, *e.g.,* for virtual transactions. This is true for both marketers and other kinds of customers.

C. Substituting Receipt and Delivery Points (PP 154 - 156)

The NOPR correctly notes that under NAS, customers will no longer have to submit a new request for transmission service and be assigned a new place in a physical transmission

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45 *See Central Hudson Gas & Electric Corp., et al.,* 86 FERC ¶ 61,062 at 61,206 (1999).

46 *See* NOPR at P 153.

queue when they change their originally requested delivery or receipt points. It also recognizes that customers can efficiently modify their CRR positions by buying new CRRs in auctions or through the secondary market.

The NOPR seeks comment on different options for handling customer requests to "reconfigure" their CRRs to avoid paying congestion when they change delivery or receipt points.[47] Existing ISO markets do not provide for CRR reconfigurations "on demand" and the Commission should not include any version of its proposal in the final rule.

It is unlikely that reconfigurations on demand would be useful to customers because it would be difficult for them to determine what CRRs they could reasonably request in exchange for their old CRRs. The combined set of new CRRs, and all outstanding CRRs, would still need to be simultaneously feasible on an ITP's transmission grid. This means that the new CRRs would need to be chosen so that they would not overload any monitored transmission constraint under any system contingency (*e.g.,* a line outage). To make a reasonable guess as to whether a new CRR requests might satisfy this criterion, and thus have a chance of being accepted, a customer would probably need to run a power flow model for the entire ITP system. This seems unlikely to be cost-effective in most cases.

From the ITP's perspective, providing for reconfigurations on demand would necessitate establishing a "first-come, first-served" queue for reconfiguration requests, an approach that would be compatible with Order No. 888, but incompatible with SMD. It is preferable to handle reconfiguration requests through periodic centralized auctions so that market forces, rather than arbitrary first-come, first-served rules determine customer priorities. The NOPR proposal could also force ITPs to constantly be conducting simultaneous feasibility analyses in response to an

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[47] P 156.

ever-growing queue of reconfiguration requests. This would be burdensome. At a minimum, limits would need to be imposed to avoid placing unreasonable hardware, software or processing requirements on ITPs. The NOPR's proposal to impose a limit on the quantity of reconfigured CRRs that customers would be entitled to receive would not suffice to mitigate the problem.

Finally, the reconfiguration on demand proposal appears to be an attempt to "translate" the Order No. 888 right to submit new requests for physical transmission service into the SMD context. There is no reason to perpetuate this aspect of Order No. 888. SMD already allows customers to modify their delivery and receipt points through their energy bids and to hedge their financial positions through periodic CRR auctions or the secondary market.

D. Load Shedding and Curtailments (PP 158 - 161)

The NYISO agrees with the NOPR that LMP is a major improvement over less sophisticated curtailment regimes and that use of LMP will greatly reduce the need to invoke Transmission Loading Relief ("TLR") procedures. The NYISO has only had to resort to TLRs once in the three years since it commenced operations.

The NYISO does not agree with the suggestion that if an "[ITP] is unable to schedule all requests for service made through the day-ahead scheduling process, those customers with [CRRs] for their requested receipt point-delivery point combinations should be scheduled first."[48] The NYISO does not provide CRR holders with any special curtailment priority.[49] When curtailments are necessary under SMD, they should be prioritized, as they currently are in New York, based on market participants' willingness to pay for the right not to have their

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48 NOPR at P 159.

49 CRR holders in the NYISO markets can obtain that kind of financial priority by submitting bids that are hedged by their CRRs to signal that they want their transactions to flow no matter the cost. This strategy would be possible under SMD without a rule giving all CRR holders a special curtailment priority.

transactions cut. By contrast, CRRs are purchased based on customers' assessment of their exposure to congestion costs, not their willingness to be curtailed for economic reasons.

Giving CRR holders a special curtailment priority would thus amount to mixing apples and oranges. It would graft a physical curtailment rule into a financial reservation system, needlessly creating significant operational problems for ITPs. At the same time, it would encourage market participants to always submit inflexible day-ahead schedules that perfectly matched their CRR holdings, further reducing ITPs' operational flexibility. Requiring ITPs to distinguish between CRR and non-CRR transactions would also hamper their ability to curtail transactions for reliability reasons. Finally, assigning all CRR holders the same priority over non-CRR holders would be less efficient than assigning curtailment priorities based on the economic preferences expressed in bids.

The NOPR proposes that "to the extent practicable, when system conditions require curtailments (in real time) that cannot be resolved through the congestion management system, the [ITP] should curtail the customers whose transactions contribute to the constraint on a *pro rata* basis."[50] The Commission should clarify that this proposal is not intended to preclude ITPs from resorting to *pro rata* curtailment only for transactions that have the same economic curtailment priority, which is the NYISO's current practice. A simple *pro forma* curtailment rule could be appropriate for inter-ITP transactions, at least until such time as financial inter-regional scheduling systems exist.

Within LMP markets, however, transactions are purely financial events and "curtailments" of them only affect financial settlements, not physical flows of energy. The choice of internal transaction curtailment rules does not affect the solution to transmission

[50] NOPR at P 159.

scheduling problems. It is therefore appropriate to base curtailments, in the first instance, on the economic preferences expressed in customers' bids and to turn to *pro rata* curtailments only for transactions with an equivalent economic priority. This system is perceived to be fair by NYISO stakeholders and has worked well. It should be allowed under the final rule.

The NOPR also suggests that load-shedding occur on a *pro rata* basis. Many ITPs will presumably be like the NYISO in that they will not directly control load-shedding, but will determine the total amount of reductions required and will then direct transmission owning utilities and load serving entities to shed load. When more than one transmission owner system must shed load, it is appropriate that the load shedding responsibility be allocated on a *pro rata* basis.

The NOPR proposes to authorize ITPs to impose a severe penalty on customers that fail to curtail after reasonable notice.[51] To date, the NYISO has not needed a penalty because it can curtail external transactions directly and no internal customer has refused to comply with curtailment instructions. Nevertheless, the NYISO believes that penalty authority can play an important backstop role in emergencies and that its existence may foster the development of improved inter-regional curtailment procedures. To avoid confusion and controversy, however, the Commission should be clear about the penalty's scope. It should clarify that penalties would apply only to external transactions since "curtailments" of internal transactions do not have any physical effect under LMP. The Commission should also clarify that in cases where ITPs do not communicate directly with individual customers[52] whether the customers, the intermediaries

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[51] *Id.* at P 160.

[52] The NYISO communicates curtailment instructions to the New York Transmission Owners. They are responsible for actually curtailing individual customers.

(normally transmission-owning utilities) that actually communicate with them, or both, will be subject to penalties.

VI. TRANSMISSION PRICING (PP 165 – 202)

A. Recovery of Embedded Costs

The NYISO agrees with the principle that customers' pre-SMD transmission rights should be respected to the extent possible.[53] The NYISO takes no position on how the final rule should handle the conversion of transmission rights that are held by *current* non-LSEs that take long-term firm Point-to-Point Transmission Service, or by LSEs in retail open-access states.[54] Whatever rule will be applied prospectively, the Commission should not revisit conversion decisions previously made in ISO regions that already operate SMD-like systems. These regions have found workable solutions to the problems identified by the NOPR, often after lengthy negotiations, settlement processes or litigation. Upsetting them would not eliminate seams or strengthen markets and would foster new controversies.

The NOPR seeks comment on whether ITPs should be permitted to continue to use "license plate" rates for a transitional period and then at some later date be required to adopt "postage stamp" rates.[55] The NYISO urges the Commission to allow ITP regions that want to continue to use license plate rates to do so without artificial termination deadlines. The Commission should not impose postage stamp rates in areas where they do not already exist.

Stakeholders in various parts of the country have undertaken extensive, and usually unsuccessful, efforts to eliminate license plate rates. There is no consensus approach to

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[53] NOPR at P 171.

[54] *See* NOPR at PP 172 -173.

[55] NOPR at P 174.

reconciling the need to protect transmission owners' revenue requirements and the need to avoid rate shifting among transmission customers. The Commission should not underestimate the difficulty of resolving this issue.

Similarly, the Commission should not overestimate the benefits that postage stamp rates will bring. Postage stamp rates are not needed to eliminate intra-regional rate pancaking because license plate rates provide for equal access to all resources in a region while avoiding cost shifting. Postage stamp rates also will not encourage the formation of larger RTOs or ITPs. In fact, the Commission's most recent RTO orders, all of which allow license plate rates to continue for many years, recognize that the adoption of license plate rates enables participants to avoid distracting fights over cost-shifting and to focus on more important issues.[56]

Finally, the Commission should allow different regions to adopt different embedded cost recovery mechanisms if the relevant Regional State Advisory Committee ("RSAC") supports it.[57] Embedded cost recovery rules are closely related to retail rates so this is as area where an RSAC's views should be entitled to deference. The Commission should ensure, however, that no new trade barriers arise when neighboring regions have different cost recovery rules.

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[56] In each of the Commission's recent RTO orders (RTO West, SeTrans, and WestConnect), the Commission found that the license plate rate design proposed by the applicants were consistent with the requirements of Order No. 2000 and approved the requests for lengthy transition periods for conversion to postage stamp rates**.** Thus, RTO West will retain license plate rates for eight additional years while SeTrans plans to utilize a license plate rate design through at least 2012 and WestConnect RTO plans to use such a rate design until January 2009. *Avista Corp., et al.,* 100 FERC ¶ 61,274 at PP 110, 133 (2002); *Cleco Power LLC, et al.,* 101 FERC ¶ 61,008 at PP 13, 105-107 (2002); *Arizona Public Service Co., et al.,* 101 FERC ¶ 61,033 at PP 110, 121, 126-127 (2002). In addition PJM recently sought and received approval from the Commission to extend the period that license plate rates will be effective in the PJM control area until December 31, 2004. *PJM Interconnection, L.L.C.,* 100 FERC ¶ 61,230 at PP 1, 12 (2002).

[57] *See* NOPR at P 174.

B. Inter-Regional Transfers (PP 179 - 189)[58]

The NYISO agrees that the elimination of multiple inter-regional transmission charges, or "rate pancaking," should promote inter-regional trade and increase competition. The ultimate goal should be the elimination of pancaking so that customers will pay only a single access charge, regardless of how many transmission owner or ITP systems are involved in a transaction. The Commission must, however, be patient because ending rate pancaking will not be simple.

As the NOPR recognizes, transmission owners are entitled to an opportunity to recover their embedded costs.[59] Mechanisms to permit cost recovery under a single access charge regime will have to be developed. This in turn raises complex retail ratemaking issues, including the effects of legislative or regulatory retail rate freezes that are of great importance to state regulatory commissions. Additionally, until non-jurisdictional transmission owners are persuaded to join ITPs, pancaking will continue to be an issue whenever a transaction flows across non-jurisdictional facilities. It follows that the only practical way to eliminate pancaking will be through negotiations among transmission-owning utilities (including non-jurisdictional entities), state regulatory commissions, other stakeholders, and the Commission itself. The Commission should be realistic about how long it will take for the parties to arrive at solutions that will allow for the elimination of pancaking. Different regions may have different amounts of money at stake and thus may need different periods of time to complete their discussions.

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[58] In addition to the views expressed herein, the NYISO also supports the position of the *Joint Comments* on these issues.

[59] *See* NOPR at P 179.

In the interim, the Commission should not hold ISOs, RTOs or ITPs accountable for their regions' progress towards eliminating pancaking. Transmission organizations can play a useful role in facilitating regional discussions but cannot solve the problem themselves or compel others to solve it. The Commission must play a leadership role.

The NOPR seeks comment on possible uniform cost recovery rules to ensure that transmission owners are able to recover their revenue requirements.[60] The Commission should resist the temptation to prescribe a uniform standard in this area. As was noted above, different regions will face different cost recovery problems and should be allowed to find solutions that reflect region-specific circumstances.

C. Application of Inter-Regional Pricing to Parallel Path Flows

The NOPR seeks comments on whether, to the extent that the Commission adopts a "true up" methodology for recovering the costs of through-and-out services, a similar methodology could be used to address parallel path flow issues. The NOPR envisions that a "true-up" mechanism could be an alternative to the use of "cooperative" parallel path flow management tools.

The NYISO urges the Commission not to prescribe a standardized approach to parallel path flow management at this time. The problems involved are among the most complex facing the industry, and no system yet devised, whether based on economic incentives or cooperative procedures, has solved them. Various initiatives are underway to try to identify and test solutions. The Commission should require regular updates on the progress of these initiatives. It should eventually hold a technical conference to review the problems and identify possible

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[60] NOPR at PP 186 - 187.

remedies. Too much work remains to be done on this issue for it to be addressed on the same timetable as the others in the NOPR.

VII. CONGESTION MANAGEMENT (PP 203 – 255)

A. Locational Marginal Pricing (PP 204 -220)

The NYISO supports the Commission's inclusion of LMP in the SMD. LMP is a major improvement on Order No. 888's congestion management mechanism, *i.e.*, *pro rata* curtailment. LMP has worked as intended in New York, despite the challenges posed by the state's often congested transmission grid, in PJM, and outside the United States. It has maximized the utilization of the grid, produced efficient price signals, and given market participants greater flexibility. LMP should work equally well in other regions once any necessary allowances are made for legitimate regional variations.[61]

The NOPR acknowledges "that in certain regions there may need to be additional rules or changes to accommodate specific regional requirements" and that there likely "will be a need to update the tariff provisions to offer new service options or to further refine the market rules."[62] It seeks comment on "how best to recognize the need for regional variation and the need for continued refinement in the rules."

The best way for the Commission to ensure that its LMP rules are, and remain, consistent with regional needs is to listen to recommendations by ITPs and other market operators. ITPs will have the best understanding of their markets and will want to work with the Commission to make them successful. The Commission should trust their insights. Furthermore, although the level of standardization proposed in the NOPR is appropriate in most cases, the Commission

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[61] *But see supra* n. 9.

[62] NOPR at P 211.

should allow regional exceptions to the LMP rules when an ITP establishes the need. This will be even more true at levels of detail below those addressed by the NOPR where ITPs will be more cognizant of small, but critical, details than the Commission. Over-standardization at that level could lead to unnecessary, inefficient and even harmful changes to successful congestion management systems.

B. Congestion Revenue Rights (PP 235 - 55)

In general, the NOPR takes a sound approach to CRR issues that will bring many benefits. Most of its proposals, with the exception of "option type" CRRs and flowgate rights, have already been tested in New York or PJM and have worked well. The NYISO supports the NOPR's proposal that "obligation type" CRRs should be a required part of SMD.

The NOPR seeks comments on whether entities that pay to construct new, non-"rolled-in" facilities that add to the grid's transfer capability should receive "credits" for the upgrades in addition to CRRs.[63] Non-CRR expansion incentives are generally unnecessary. Entities that pay to construct new facilities that are not rolled-in should receive the CRRs associated with the new transfer capability.[64] The only exception is when system upgrade facilities increase the fault current or short circuit interrupting capability of the grid. The NYISO's practice[65] is to give facility owners credits for the "head room" they create. These credits can then be purchased by subsequent facility owners that consume the "head room."

The Commission should clarify its proposal to require ITPs to offer receipt point to delivery point options and flowgate rights "upon the request of a market participant" as soon as it

63 NOPR at P 238.

64 The NYISO believes that option-type CRRs should be considered in expansion cases and is working with its stakeholders to design an appropriate allocation mechanism.

65 See NYISO OATT at Attachment S, Section IV.-12. (Original Sheet No. 686).

is feasible to do so.[66] Because it will take substantial time and resources to implement such rights and options, it would not be appropriate to let a single market participant force an ITP to establish them. These mechanisms are unproven and, based on existing ISOs' experience, are not essential to the efficient performance of SMD. No market participant should be allowed to dictate that an ITP postpone other, more important, projects and work on flowgates first. The final rule should therefore permit ITPs, in consultation with their stakeholders, to determine whether they want to develop receipt point to delivery point options and flowgate rights. If they do, they should be permitted to set up an implementation schedule that considers other regional priorities.

The NOPR also seeks comment on whether ITPs should be required to offer multi-year CRRs at the time that SMD is first established, and whether the duration of CRRs should be tied to the region's resource adequacy planning horizon.[67] Long-term CRRs play an important market role and should ultimately be offered by all ITPs. It would be unwise, however, to insist that these rights be made available immediately. Until a region has some experience with CRR auctions and SMD operations, it will be hard for market participants to accurately assess the value of long-term CRRs. Requiring premature auctions of these products would likely result in potentially valuable rights being sold at deeply discounted prices.[68] This was the NYISO's experience when it auctioned two-year and five-year TCCs soon after commencing operations. No ITP should be forced to repeat this experience although ITPs should be given discretion to

[66] NOPR at P 248.

[67] NOPR at P 249.

[68] At P 380, the NOPR acknowledges the possibility that "[s]ince congestion patterns can change significantly after the implementation of LMP, there may be a benefit to delaying the auction of multi-year CRRs until after a start-up period."

auction long-term TCCs at the inception of their markets if it concludes that its region is ready for them.

The Commission should not mandate a link between CRR terms and a region's planning horizon. The Commission should not presume that rights of that duration will be useful, but should trust that market participants will request, and that ITPs will provide, them if they are useful. Instead of attempting to prescribe standard CRR terms, the Commission should let each region determine what kinds of CRRs are needed in light of regional conditions. This is what is currently done in the NYISO-administered markets.

The NOPR requests comments on how to address the revenue shortfall that can arise when a significant number of transmission facilities are out of service and an ITP collects less congestion revenue than it needs to pay CRR holders.[69] The NYISO supports the Commission's preferred "full-funding" approach under which any revenue shortfalls (or excesses) will be assigned to transmission owners and all CRR holders will continue to be fully hedged.[70] This method is superior to the "partial funding" alternative because it gives transmission owners an incentive to minimize transmission outages, and ensures that CRR holders receive the full value of the rights they paid for. Full-funding has worked as intended in New York for several years by providing transmission customers with price certainty.[71] Nevertheless, because the allocation of congestion revenue shortfalls and excesses is a complex matter, the final SMD rule should allow ITP regions to develop allocation mechanisms that meet their region-specific needs.

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[69] NOPR at P 251.

[70] The NYISO supports the NOPR's proposed force majeure exception to the full-funding rule.

[71] Although there has not been significant transmission expansion in New York in the last few years there is no reason to believe that the NYISO's full-funding rules have contributed to the problem.

Finally, the NYISO supports the NOPR's proposal that there be secondary CRR markets, and periodic ITP-administered CRR auctions.

VIII. DAY-AHEAD AND REAL-TIME MARKET SERVICES (PP 256 – 327)

The NYISO is pleased that the NOPR's proposals for day-ahead and real-time energy and ancillary services markets are consistent with the NYISO's market design. The same is true with respect to the NOPR's ancillary services market proposals. The core market design components, *i.e.,* a voluntary, financially-binding bid-based security-constrained dispatch with implicit financial transmission reservations, financial congestion hedging rights, multi-settlement energy markets and simultaneously co-optimized multi-settlement ancillary services markets have proven themselves in New York and other markets. They should work well in other regions, although some of the details may need to be changed in to reflect differences in local resource mixes or reliability constraints.

The NOPR proposes several new market design features that are not part of the current NYISO (or PJM) designs and that will be particularly difficult to implement. Specifically, the NOPR calls for market participants to have a general capability to specify the maximum congestion charge they are willing to pay and to submit multi-hour block bids with a maximum total price tolerance. These features are currently available in the NYISO-administered markets only under limited circumstances. Expanding their scope will be a major undertaking. The NYISO understands that these proposed features are attractive to many market participants, but is concerned that if they were made an immediate priority, it would have to divert resources from market enhancements that promise substantially greater benefits. It seems likely that other regions' work on core SMD components would also be delayed if they were required to focus on "up to" bidding features right away. ITPs should therefore either be given the option of not implementing these features or of pursuing them after other aspects of SMD are in place.

Details of certain other NOPR market design proposals should also be clarified in the final rule. These features are discussed the sections that follow.

A. Allowing Customers to Specify the Maximum Transmission Usage Charges and the Maximum Congestion Charges They Are Willing to Pay (P 258)

The NOPR proposes that:

> [t]o facilitate the ability of demand to respond to price signals, transmission customers will be given several ways of indicating their willingness to change their consumption based on congestion costs and marginal losses: (1) customers (whether or not they hold Congestion Revenue Rights) would be allowed to specify in their scheduling requests the maximum transmission usage charge (reflecting the costs of congestion and marginal losses) at which the customer desires service; (2) customers would be allowed to specify the maximum congestion charge component of the transmission usage charge at which they desire transmission service, or above which they are unwilling to pay any congestion costs . . . .[72]

In principle, allowing customers to specify the maximum transmission usage charge they are willing to pay is appealing because it would enable them to express their economic preferences more precisely. As a practical matter, however, "up to" bidding would bring relatively few market near-term benefits and significant near-term burdens. Major software modifications would be needed to make unrestricted "up to" bidding available in connection with both internal and external transactions. If "up to" bidding were used extensively, it would impose heavy computational burdens on ITPs which could increase the time needed to solve security-constrained unit commitment ("SCUC") problems. This could reduce the efficiency of ITP markets and operations. Unrestricted "up to" bidding for internal transactions could also

[72] NOPR at P 258 (footnote omitted).

facilitate transmission withholding and the exercise of market power.[73] Technological advances may well eliminate these problems and permit wider deployment of "up to" bidding, but they are unlikely to arrive for several years.

To the best of the NYISO's knowledge, no existing market design incorporates the proposals to the extent contemplated by the NOPR. This suggests that market designers have generally concluded that the benefits of the NOPR's proposals do not exceed their costs given existing hardware and software capabilities.

The NYISO allows "up to" bidding only for wheel through transactions. PJM makes it more broadly available to "external" transactions (*i.e.,* imports, exports and wheel-throughs), but has a $25 bid cap. PJM has mitigated the technical difficulties associated with "up to" bidding by accounting for it only in the "dispatch step"[74] of its day-ahead market ("DAM") software. Unfortunately, this approach would not work well if it were applied to a more congested system, like New York's, where failing to account for "up to" bids in the "commitment step"[75] would create new gaming opportunities.[76] This would be especially true if SMD includes nodal pricing for both suppliers and loads.

Consequently, the Commission should either not make "up to" bidding a required part of SMD or should allow substantial additional time to introduce it. If the Commission decides to require "up to" bidding, it should consider adopting a more limited program for a transition

[73] This is because "up to" congestion bids are effectively requests to withhold transmission capacity from the market until congestion costs exceed the amount bid.

[74] The dispatch step is the stage in the PJM DAM software in which prices and schedules are determined in light of the unit commitment.

[75] The commitment step is the stage in the PJM DAM software in which it is determined whether individual generators will be on- or offline for a given hour, *i.e.,* it is where unit commitment decisions are made.

[76] The NYISO's DAM software accounts for "up to" bids connected in both steps.

period, such as PJM's "external" model, the NYISO's wheel-through model, or allowing "up to" bidding solely between zones and/or trading hubs. A transitional bid cap modeled on PJM's should also be considered.

B. Allowing Customers to Specify the Maximum Total Multi-Hour Block Transaction Congestion Price They Are Willing to Pay (P 259)

In the interest of facilitating responses to price signals, the NOPR would allow customers to submit "multi-hour block bids, requesting transmission service for a block of consecutive hours and indicating the maximum price for the entire multi-hour period." The NOPR observes that "[t]his feature has not been put in practice in any of the bid-based markets operated by the ISOs," and seeks comment "on its merit and any implementation difficulties."

The maximum congestion price aspect of this proposal[77] raises the same issues as the "up to" bidding proposals described above, would probably have an even greater near term effect on the efficiency of ITPs' security constrained unit commitment processes and should not be a mandatory part of SMD. Until the relevant technology improves, the proposed enhancement is unlikely to bring significant benefits and likely to impose significant costs and create implementation difficulties.[78] Like "up to" bidding, maximum multi-hour congestion price bidding has not been aggressively pursued by stakeholders. Insisting on implementation before systems capable of properly supporting the new enhancement are in place could likewise create new gaming opportunities.

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[77] The NYISO currently allows multi-hour block bids in connection with external transactions and agrees that they should be part of SMD.

[78] In particular, this feature would tremendously expand DAM computational requirements by necessitating hourly calculations to consider variables that span multiple hours.

Thus, as with "up to" bidding, the Commission should not make maximum multi-hour congestion price bidding a mandatory SMD component. Instead, the Commission should either allow it to be implemented in a more limited form or allow additional implementation time.

C. Scheduling Longer-Term Transmission Service (P 263)

The NOPR notes that its proposed market and network access rules are generally focused on daily transmission reservations. It seeks comments on "whether a customer should be allowed to provide a schedule for multiple days or have a standing scheduling request that remain in effect until changed by the customer." All such scheduling requests would be financially binding.

The NYISO's DAM software currently permits market participants to submit day-ahead schedules up to fifteen days in advance. All schedules are essentially "standing" requests because they automatically carry forward from day to day unless a market participant takes action to change them. Schedules are not cleared in the DAM, however, until all market participants have submitted their bids. This basic approach has worked well and could be adopted for SMD. It will likely be possible to allow advance scheduling further into the future as technology improves.[79]

D. Transmission Service Across Borders (PP 264 - 266)

The NOPR notes that transmission service across multiple ITPs will require close inter-ITP coordination. It proposes to switch from the current Order No. 888-based physical reservation system for reserving inter-regional transmission to one based on the NAS model for

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[79] It may ultimately be possible to build on tools like the NYISO's current inter-ISO pre-scheduling mechanism, which accommodates reservations up to eighteen months in advance, and allow long-range scheduling for intra-ITP transactions. Such an expansion is not currently planned in New York, and could not be completed quickly, but could happen in the intermediate term if it were required.

scheduling intra-ITP transactions, *i.e.,* financial scheduling. The NYISO supports the change in principle, but cautions that making it will raise complex issues and take substantial time. It will be challenging to develop a successful inter-ITP financial scheduling system, and essential to do the job right. Managing financial schedules across ITP boundaries is different from managing them within an ITP because multiple bid-based markets are involved A dependably accurate forward coordination mechanism is needed to provide certainty and avoid the major scheduling and dispatching problems that could arise if a reservation were accepted by one ITP's economic analysis but not the other's. No such coordination mechanism has yet been created, but the NYISO,[80] and other ISOs, are studying a number of promising alternatives. There is reason for optimism that at least one of them will prove viable, but it would be premature to try to pick a winner now. The Commission should hold a technical conference some time after a final rule is issued to permit it to make a more informed decision.

The NOPR raises the possibility of allowing customers to specify the maximum transmission usage charge ("TUC") that they are willing to pay on either side of an ITP boundary.[81] The Commission should clarify whether the NOPR's proposal pertains to TUC charges within each ITP or to the price differential between ITP proxy buses. In either case, the NYISO agrees with the proposed feature in principle but believes that it should either be an optional part of SMD, or that it should be a SMD component that may be phased in after the primary SMD implementation deadline. If the proposal has to do with intra-ITP TUCs, then it should be feasible to implement at the same time as "up to" bidding. On the other hand, if the proposal is meant to relate to inter-ITP TUCs, it will not be possible to introduce until there is an

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[80] Reference the Open Scheduling System (O.S.S.).

[81] NOPR at P 265.

accurate way to calculate congestion at ITP borders. Past efforts to create inter-regional congestion management systems have only been partially successful and it will take time to overcome the technical challenges involved.

The NOPR also seeks comment on whether a physical prescheduling option similar to that developed by the NYISO[82] should be included in SMD.[83] The NYISO believes that its prescheduling tool has been useful and recommends that it be retained as a transitional device until fully financial inter-ITP reservation systems can be developed. At the same time, the Commission should be aware that the NYISO's prescheduling option has been relatively little used. This suggests that, at least under current market conditions in the Northeast, there is little demand for long-term inter-Control area transmission reservations. The NYISO respectfully suggests that the Commission consider this as it determines how much priority to attach to the development of long-term inter-ITP transmission models and physical pre-scheduling mechanisms.

E. Transmission Losses (PP 267 - 268)

The NOPR seeks comments on whether transmission losses should be recovered on the basis of the marginal cost, or the average cost of losses. The NYISO recommends that the final rule adopt a marginal cost methodology,[84] as is currently used in New York. The marginal losses methodology is more consistent with LMP principles because it sends customers a price signal concerning the current cost of losses associated with their transactions. It ensures that customers

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82 *See N.Y. Indep. Sys. Operator, Inc.*, 99 FERC ¶ 61,292 (2002).

83 NOPR at P 266.

84 Under the marginal losses methodology, the ITP calculates the real-time marginal cost of losses at the relevant points of delivery and receipt. All customers pay the marginal price, *i.e.,* the cost associated with the addition of the next MW of load to the system.

pay for losses based on their actual use of the system and is compatible with the SMD approach to calculating congestion charges. By contrast, the average losses methodology blunts efficient economic signals by computing an average loss factor for "typical" conditions and socializing the costs. Furthermore, the NOPR is wrong to suggest that the average cost methodology has the advantage of simplicity. A true average losses system would be unworkable.[85] The California ISO discovered this when its attempts to use an average losses methodology contributed to its market dysfunctions. The disadvantages of using average cost losses far outweigh the single flaw of a marginal losses system, *i.e.,* the need to account for and refund excess charges for losses. This problem can be remedied by crediting net charges for losses against the uplift charges allocated to each LSE.

The NOPR also seeks comment on whether "transmission customers should have the option of paying for losses in cash or in kind, or, alternatively, whether all transmission customers should be required to pay for losses in cash."[86] The NYISO believes that it would be appropriate to allow "payment-in-kind" by market participants that self-schedule injections greater than withdrawals based on their estimate of losses. This option should not be available to other participants because a physical loss payback system would greatly complicate scheduling, while bringing only minor market benefits. ITPs should not be responsible for estimating future marginal loss factors but should assist market participants by publishing past loss factor data. As

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85 PJM's losses pricing system is "workable," but it is not a true average cost methodology because it does not account for the cost of losses in either dispatching generators or calculating prices. Its dispatching and pricing decisions therefore essentially ignore losses. By contrast, the NYISO's methodology considers the marginal cost of losses both when dispatching generators and calculating prices.

86 NOPR at P 268.

the NOPR indicates, customers seeking to pay in-kind losses should bear the risk of being charged or credited the applicable LMP for any under- or over-provision of losses.

F. Day-Ahead Market: General Features, Bidding/Scheduling (PP 269 - 276)

1. Voluntariness (P 269)

The NYISO supports the NOPR's proposal that DAM participation be voluntary. The Commission should clarify, however, that the fact that generators need not participate in the DAM does not mean that they may withhold. Generators must be available to ITPs when they are committing resources to meet reliability requirements for the following day. In these cases, a resource's commitment costs would be guaranteed, but the resource owner would not be required to accept a financially binding day-ahead energy contract above its minimum generation level. Therefore, resources that are needed for reliability purposes in transmission constrained areas, or are needed to meet the region's forecasted load, should not be able to engage in physical withholding.

2. Multi-Part Bidding (PP 270 - 273)

The NYISO supports the NOPR's proposal to allow physical suppliers and loads to submit multi-part day-ahead bids, provided that sufficient time is allowed for implementation.[87] The NYISO does not, however, support multi-part day-ahead bidding for virtual suppliers or virtual loads.[88] The Commission should clarify that multi-part virtual bidding will not be allowed.

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87 NOPR at PP 271 - 273.

88 NOPR at P 272 suggests that the Commission contemplates multi-part, day-ahead virtual bidding. However, Sections 2.3.2 and 2.4.3 of Part III of the SMD Tariff indicates that multi-part virtual bids will not be allowed.

No existing market includes multi-part load bidding, and it will be necessary to proceed deliberately to avoid the market distortions that an unsuccessful implementation would create. The NYISO recommends that multi-part load bidding at first be available only to physical loads that have real-time metering and thus have the ability to respond to price signals in real time. Adopting this approach would probably mean that only a limited amount of multi-part load bidding would initially occur, but it would be available to all loads that could realistically take advantage of it. ITPs could gain experience with the new bidding option, fix problems that could lead to gaming and find ways gradually to manage greater numbers of multi-part load bids over time.

It is understandable that the Commission would want to provide all sellers and buyers with perfectly symmetrical bidding opportunities, but practical reasons prevent unrestricted multi-part load bidding for virtual supply and load in existing markets. First, market participants lacking assets that respond to real-time prices or dispatch instructions and do not settle based on their real-time injections or withdrawals have no competitive need to submit multi-part bids reflecting asset characteristics. Second, the computational burden of handling potentially thousands of multi-part virtual load or supply bids would overwhelm any existing system.

The NOPR may be defining multi-part bidding too broadly when it notes that sellers' bids may include "technical characteristics such as ramp rates, minimum run times and minimum down times."[89] In the NYISO market design these are static values that suppliers provide, and change administratively, but do not include in each bid. The NYISO does not believe that suppliers have objected to this arrangement. It is also concerned that making these parameters

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[89] NOPR at P 271. The NOPR also provides for "parameter bidding" in the Day-Ahead ancillary services markets. *See* NOPR at P 289.

biddable on an hourly basis would unnecessarily complicate ITP scheduling algorithms and create gaming opportunities. "Parameter bidding" should therefore not be part of SMD.

The NOPR proposes to allow hourly bid price changes.[90] The NYISO supports this proposal, which reflects the practice in the New York markets. The ability to make hourly bid price changes provide market participants with needed flexibility. In the NYISO's experience, hourly bid price changes have not led to the kind of real-time market abuses that some fear it would permit. For the most part, the feature is used by suppliers to lower their offers in order to increase participation in real-time. In addition, this feature appears to be important to energy limited resources ("ELRs") because it enables them to accurately reflect their changing energy costs in real-time as water supply conditions change.

3. Scheduling Energy Limited and Intermittent Resources (PP 274–275)

The NOPR proposes a special scheduling option that is designed to address the scheduling needs of ELRs,[91] although the NOPR suggests that it might also be available to non-ELRs.[92] The NOPR seeks comment on whether "other scheduling options or regional variations should be included for energy limited resources in the tariff."

The NYISO encourages the Commission to be flexible and allow the development of regionally appropriate mechanisms for the efficient ELR scheduling. These include the NOPR's proposal to allow ELRs to submit DAM bids specifying the amount of energy, or the number of hours, available the next day and request that their energy be scheduled in those hours of the next

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[90] NOPR at P 273.

[91] Specifically, ELRs would be allowed to submit DAM bids specifying the amount of energy, or the number of hours, available for production over the next day and to ask the ITP to schedule their energy in those hours of the next day when it will minimize overall bid production costs.

[92] NOPR at P 274.

day when the energy price is highest. The Commission should, however, clarify the NOPR's statement that ELRs should be allowed to schedule in a way that ensures their energy "would have the greatest value, with maximum profit to the generation owner." This language might be read as requiring ITPs to withhold ELRs' output when it would maximize profits. The Commission should instead specify that ELRs be scheduled in a manner that is consistent with the energy constraints identified in their bids and minimizes the bid production cost of meeting DAM load.[93] Consistent with the NOPR's objective, this will usually result in ELRs being scheduled during hours when prices are highest.

In New York's case, the Commission should allow the NYISO, or its successor in interest, to continue to use existing rules that have worked well. The most important example is the use of the "ELR/CLR"[94] procedure in the hourly market, which allows a system operator to shift previously scheduled production in real-time, while holding generators harmless, when such shifts are necessary to preserve reliability.

The NOPR seeks comment on whether the California ISO's scheduling option for intermittent generators should be included in the SMD or if there is a better way to schedule intermittent resources.[95] The California ISO's approach has a number of attractive features, but the NYISO has previously determined that somewhat different rules would a better fit for New York. In general it seems likely that regions with different intermittent resource profiles would be best served by region specific scheduling rules tailored to the regional resource mix. The Commission therefore should not adopt a standard national rule in this area.

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93 The NYISO plans to implement this rule as part of its RTS initiative.

94 The Commission accepted this procedure in a Letter Order in Docket Nos. ER01-2459-000 and ER01-2459-001 dated August 27, 2001 (96 FERC ¶ 61,225).

95 NOPR at P 275.

4. Demand Response Programs (P 276)

The NOPR expresses a preference for the "direct approach" of letting demand resources submit bids directly into ITP-administered energy markets instead of a system that makes administrative payments to end-users to reduce demand when energy prices reach a pre-determined level.[96] It also seeks comment on whether additional measures are needed.

The NOPR mistakenly asserts that all existing ISO demand response programs are "administrative" in nature, when in reality the NYISO's existing Day-Ahead Demand Response Program already permits demand resources to submit demand reduction bids in the DAM. These bids are treated the same as suppliers' bids and can set the market clearing price. The NYISO will introduce real-time market ("RTM") demand bidding as part of its RTS upgrades for participants that can respond to dispatch signals or to other short-term scheduling instructions.

In any event, the NYISO agrees that the final SMD rule should permit demand resources to bid into energy (and ancillary services) markets on terms comparable to suppliers, to the extent that they have the technical capability to participate. It is likely that few resources will meet these criteria initially but their numbers should increase over time. The Commission should continue to encourage demand participation, both through the SMD proceeding and through other initiatives.

Until State retail pricing policies allow for robust market-based DAM and RTM demand response mechanisms, which will only occur if retail load is exposed to RTM prices, the Commission should allow ITPs to continue to use more administrative emergency response programs. The NYISO has found that such programs bring many benefits and believes that it would be premature to terminate them given the limited responsiveness of demand at this time.

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[96] NOPR at P 276.

Indeed, in regions that are capacity constrained, it will be appropriate to expand their role. In the near-term, it will also be necessary to continue to include subsidies in these programs in order to encourage sufficient participation by demand resources. The need for such subsidies should be periodically re-evaluated and they should ultimately be eliminated. It may also be necessary to modify certain aspects of these programs so that they do not artificially depress prices during scarcity conditions.

For example, the NYISO recently proposed to extend its existing Emergency Demand Response Program ("EDRP")[97] until October 31, 2005. It is also developing proposed improvements to both its EDRP and its Installed Capacity Special Case Resources ("SCR") program[98] so that they will be better coordinated and will not mute scarcity price signals.[99] The final SMD rule should support these initiatives and similar ones that may be developed in other parts of the country.

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97 Under the EDRP, qualified demand resources are paid for reducing their energy consumption when the NYISO declares that an operating reserves deficiency or major emergency exists. There is no obligation to respond to the NYISO's declaration. Participation in the program occurs through "Curtailment Services Providers" which are paid $500/MWh for verified load reductions. As of September, 2002, approximately 1500 MW of interruptible loads and on-site generation resources were registered in EDRP. The EDRP has been activated eight times since its inception in May 2001.

98 Under the SCR, retail electricity customers are paid for making their load reduction capability available over a specified contract period. Thus, SCR participants are paid in advance for agreeing in advance to curtail usage during times when the grid could be jeopardized. Unlike, EDRP participants, SCR participants are subject to penalties if they fail to curtail on the NYISO's request.

99 Among other things, the NYISO would: (i) call on SCR participants before calling on EDRP participants (they are currently called upon simultaneously); (ii) allow SCR participants to submit minimum strike price offers which will give the NYISO a mechanism for choosing how much demand response is needed; (iii) allow SCR strike prices to set the RTM clearing price; and (iv) clarify that if EDRP resources were called that the RTM clearing price would be set at $500.

G. <u>Day-Ahead Market: Price Determination and Settlements (PP 277 - 283)</u>

The NYISO supports the NOPR's proposals to: (i) require the calculation of a single market clearing price at each system node;[100] (ii) permit the creation of trading hubs or optional pricing zones at the request of a region's stakeholders; and (iii) make the DAM results financially binding on buyers and sellers.[101] All of these features either already exist in the NYISO-administered markets or will be implemented in the RTS initiative.

The NOPR appears to propose that uplift charges would be imposed exclusively on customers that purchase energy or ancillary services in the DAM.[102] The Commission should clarify whether this is the NOPR's intent. If it is, then several aspects of the proposal are troubling. First, it would provide LSEs with an artificial incentive to meet their needs through RTM purchases, instead of through the DAM. This is inconsistent with the Commission's desire to encourage forward markets and minimize LSEs' reliance on more volatile RTM prices. From the ITP's perspective, it is also preferable that customers submit day-ahead bids since it will then be easier to develop a secure operating plan for the next day.

Second, allowing entities that self-supply to bypass uplift charges would give them a strong incentive to take dispatchable generation off-dispatch, which would undermine market efficiency and reliability. Efficiency would be undermined because suppliers and loads that are

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[100] Under RTS/SMD 2.0, the NYISO (or its successor) will compute DAM and RTM prices at each node and will use nodal prices for settlement with entities that provide individual metering information (*i.e.,* generators and large (1 MW +) loads.) Nodal prices will be used to calculate aggregated zonal prices for use in settlements with other load-serving entities. The NYISO is not proposing that retail loads be exposed to nodal prices directly since this is a retail rate design issue. The NYISO believes that this approach is consistent with P 279's requirements.

[101] NOPR at PP 277 - 279.

[102] NOPR at P 280.

subject to forward contracts should, nevertheless, make their resources available for economic commitment and dispatch through the DAM and RTM. Loads that self-schedule uneconomic resources to avoid bearing an uplift allocation might cause the market to forego lower-cost resources and distort energy prices.

Third, self-supplying customers may create uplift costs when generators must be committed to manage congestion in order to allow self-supply transactions to flow. Given the foregoing, the Commission should revise the NOPR and require all loads, including those that self-schedule, purchase in the DAM, or purchase in RTM, to bear a share of uplift costs.

The NOPR seeks comment on whether generators that reduce their production of real power in order to produce reactive power should recover their lost opportunity costs, or the higher of lost opportunity costs, or the value of the additional transfer capability. [103]

The Commission should, at a minimum, allow generators that are dispatched out-of-merit in order to provide needed reactive power to recover their opportunity costs. This is necessary to ensure that generators are fully compensated and do not have a disincentive to supply reactive power. ITPs should be permitted to develop more sophisticated mechanisms to provide reactive power more efficiently, but it would be premature to mandate a particular approach. No model has been shown to be workable, and there are a number of potential complications to contend with. Most importantly, market power is more likely to arise in reactive power markets because of the inherently localized nature of the product. Special reactive power mitigation rules may therefore be required. There could also be difficult settlement issues. In short, the Commission should be cautious about expanding the reactive power compensation mechanisms that will be part of SMD.

[103] NOPR at P 283.

H. Day-Ahead Market: Ancillary Services (PP 284 - 297)

The NYISO generally agrees with the NOPR's ancillary services proposals and commends the Commission for including voluntary, bid-based, multi-settlement ancillary services markets, especially reserves markets, in the SMD. The NYISO also strongly supports the Commission's proposal, at P 290, to require the simultaneous co-optimization of energy and ancillary services markets. Although ancillary services markets will be relatively small compared to the size of energy markets, simultaneous co-optimization is nonetheless a critical design feature. During scarcity conditions, when prices are volatile, simultaneous co-optimization prevents artificial price increases by increasing an ITP's ability to select the optimal combination of energy and ancillary services and make optimum use of scarce transmission capacity. Non-co-optimized "sequential" systems are less flexible and thus less effective at both minimizing the total cost of both energy and ancillary services and maximizing the use of existing capacity. This flexibility is especially important in systems, like New York, that have locational transmission constraints that cause local scarcity conditions to arise more frequently.

It is important to ensure that co-optimization procedures allow the true cost of scarcity to be reflected in price signals. The NYISO is currently focusing a great deal of attention on this issue. The Commission should also consider it carefully as it finalizes SMD.

The NYISO also strongly supports the NOPR's proposal to adopt a flexible definition of "operating reserves – supplemental." Different regions will have different reliability needs that necessitate different kinds of operating reserves. Reserve markets may be a lower priority for other regions than they are for New York. The Commission would be wise to adopt a flexible SMD rule that accommodates these differences.

The Commission seeks comments on whether "Scheduling, System Control and Dispatch Services" should be "treated as a basic cost of providing transmission service instead of an ancillary service."[104] The NYISO incurs a wide range of costs when performing market and transmission functions related to "Scheduling, System Control and Dispatch Services." Those costs are more diverse than costs recovered under other ancillary services schedules. Assuming that this will be the case under the final rule, the NYISO agrees that it would be appropriate to treat "Scheduling, System Control and Dispatch Services" as a group of transmission and market functions rather than a distinct ancillary service.

In addition, the Commission notes that customers will be allowed to meet their ancillary services requirements through self-supply, third party supply or through the ITP-administered markets.[105] This is a good proposal, if the Commission recognizes that financial self-supply arrangements will be far superior to physical ones in some regions. Order No. 888's physical self-supply construct is generally an awkward fit for financial reservation systems. When transmission systems are constrained, as is often the case in New York, it will almost always be economically irrational to physically reserve transmission for the self-supply of ancillary services because energy should always be more valuable.[106] Financial self-supply arrangements will also be more attractive once multi-settlement ancillary services markets, which will increase price certainty, and a mechanism like PJM's "E-Schedules," which will increase financial flexibility, are established.

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[104] NOPR at P 284, n. 149.

[105] NOPR at P 296.

[106] The only exception would be if market power abuses were artificially inflating ancillary services prices.

Finally, the Commission notes that exports are not charged for ancillary services under the Order No. 888 regime and seeks comments on whether they should be under SMD.[107] In the NYISO, exports are already charged ancillary services because, unlike Order No. 888, external and internal transactions are treated alike for most purposes.[108] In other words, operating reserves are utilized prior to the curtailment of exports which is why it is appropriate to assess the charges instead of treating them as a rate "pancake" to be eliminated. The same should be true under SMD, particularly because the Commission is proposing to adopt financial scheduling for both external and internal transactions.

I. Scheduling After the Close of the DAM and Changes to Transmission Schedules (PP 298 – 304)

The NOPR proposes replacement reserves rules that differ markedly from the NYISO's.[109] The proposed rules, however, are viable and the NYISO does not object to them.[110] One point of concern is the proposal to fund uplift payments used for replacement reserves solely from loads that buy RTM energy and that are not scheduled day-ahead.[111] Uplift costs associated with resources committed in real-time should be allocated both to RTM loads that are not scheduled in the DAM and to "virtual supply," *i.e.,* supply scheduled day-ahead that would

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107 NOPR at P 296.

108 *See Central Hudson Gas & Elec. Corp., et al.*, 95 FERC ¶ 63,013 (2001) (ALJ Cowan) (holding that export transactions should not be exempt from the NYISO's ancillary services charges.); 100 FERC ¶ 61,023 (2002).

109 NOPR at P 300 (proposing that replacement reserves be procured after the close of the DAM.) Under the NYISO's market design, replacement reserves are procured in the DAM.

110 At the same time, the NYISO's current approach has the benefit of creating a price dynamic that encourages loads to buy in the DAM instead of the RTM. The dynamic arises because purchases to serve expected, but un-bid, load tends to depress DAM prices and increase RTM prices as load moves from the DAM to the RTM.

111 NOPR at P 301.

otherwise be economic and does not operate in real-time. Unless this change is made, real-time loads could evade the uplift charges simply by submitting virtual supply bids. Because there are advantages and disadvantages to both the NOPR's and the NYISO's models the Commission should allow ITPs to choose between them.

The NYISO also supports the NOPR's proposed rule on transmission schedule changes.[112]

J. Real-Time Energy and Ancillary Services Markets (PP 305 - 25)

As was the case with the NOPR's day-ahead energy and ancillary services proposals, the NYISO strongly supports the core components of its proposed RTM design. These include the use of a voluntary, but financially binding, bid-based security-constrained dispatch with simultaneously co-optimized ancillary services. The NYISO also supports allowing ancillary services suppliers to submit multi-part bids.

Certain NYISO market participants are concerned that existing RTM pricing rules may under-compensate suppliers during scarcity or emergency conditions. The NYISO is studying these issues but has not yet reached any conclusions. The final SMD rule should be sufficiently flexible to allow for the introduction of special real-time scarcity pricing rules, either on a national, or on an ITP-by-ITP basis, if they are shown to be justified.

The Commission should clarify the NOPR's multi-part real-time load bidding provisions.[113] If the intent is to support the development of direct, real-time demand reduction bidding, the NYISO supports the proposal.[114] If, however, the NOPR intends to establish some

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[112] NOPR at PP 303 - 304.

[113] NOPR at P 307.

[114] As is noted above, the NYISO intends to introduce RTM demand bidding as part of its RTS/SMD 2.0 initiative.

other real-time bidding mechanism, it would helpful if the Commission could provide more details. In existing SMD-type markets, load either appears in real-time or it does not. The NOPR's proposal could be read as requiring all loads to respond to dispatch signals in the same manner and timeframes as generators. Most loads lack the capability to receive or respond to such signals. Worse, if loads failed to promptly follow the signals, they would create unacceptable computational, operational and reliability problems for ITPs. Thus, loads should simply take service in real-time and settle deviations from their day-ahead purchases at real-time prices. They should not be required to submit bids, unless they are individually metered and dispatchable in real-time or are providing ancillary services.[115]

The NYISO also asks that the Commission reconsider the need for "parameter bidding" in the RTM,[116] just as it has in the DAM.

The Commission should revise its statement that real-time bids should "indicate the increase or decrease (in MWhs) from the day-ahead schedule in the amount of energy to be sold or purchased in real time, and the location and the hour of the changed purchase or sale."[117] Read literally, this suggests that the Commission has in mind California's system of "incremental" and "decremental" bidding which was necessary under its "balanced schedule" regime.[118] By contrast, incremental and decremental bidding are not part of the NYISO or PJM market designs which, like the NOPR, do not require balanced schedules. Developing software

115 There is currently no load in the New York Control Area that has these characteristics. It seems likely that few loads would be capable of responding in real-time, at least in the near term.

116 *See* NOPR at P 307 ("Each participant bidding into the [RTM] would be allowed to include multi-part bids similar to those allowed in the [DAM] . . . .")

117 NOPR at P 307.

118 If, however, the Commission simply meant that offer curves implicitly describe a willingness to depart from day-ahead schedules, then the NOPR language is consistent with the NYISO's and PJM's practice.

to accommodate incremental and decremental bidding would be expensive and time-consuming and probably would not yield system improvements. The Commission should clarify that the use of "bid curves" consistent with the current practice in the NYISO and PJM markets will satisfy SMD's requirements.

The NOPR states that ITPs should determine real-time energy prices every five minutes or for some other "subhourly period where a 5-minute determination is not technically achievable."[119] The NYISO normally uses a five minute security-constrained dispatch interval, which has worked well and given generators clear incentives to follow dispatch instructions. The NYISO has observed, however, that conditions sometimes warrant the use of a different subhourly calculation interval, *e.g.*, three, six or ten minutes. The Commission should recognize this and give ITPs flexibility to deviate from their usual real-time calculation intervals when circumstances warrant.

The NOPR discusses the relative merits of calculating real-time prices on an *ex ante* and *ex post* basis.[120] It concludes that ITPs should use *ex post* pricing but seeks comments on its choice. The NYISO currently uses the *ex ante* method but is considering moving to an *ex post* system as part of the RTS/SMD 2.0. It does not object to the Commission's proposal. The Commission should understand, however, that requiring the use of *ex post* pricing in all situations would have some undesirable consequences. First, *ex post* pricing requires that resources which set prices have sufficiently good metering and communications links to permit an ITP to verify their output in real-time. This requirement could prevent many demand-side resources from being included in an ITP's price calculations which would be contrary to other

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119 NOPR at P 310.

120 NOPR at PP 313 - 315.

aspects of SMD. Second, an absolute requirement to use *ex post* pricing would appear to preclude ITPs from determining prices during shortage conditions based on reserve deficiencies, which is the most efficient method, and to instead compel them to calculate prices based on dispatch instructions and generator output. Third, if SMD will allow hourly bid changes, and if the NOPR's proposal to allow "lumpy" generators to set day-ahead prices (see Section VIII.K below) is adopted, it will be necessary for the ITP to account for offers by off-line, quick start units in order to calculate prices correctly. It is not clear whether this could be done using a pure *ex post* pricing methodology. Fourth, it is also unclear whether a pure *ex post* methodology will always produce accurate prices under scarcity conditions. Consequently, if the Commission adopts *ex post* pricing, it should give ITPs some degree of flexibility to use different methods in situations when doing so would be more accurate. It would be appropriate to allow individual ITPs to opt for *ex ante* pricing, either for specific circumstances, or for more general use, if they conclude that it would be a better option.

The NOPR seeks comments on "whether market participants should face additional charges for 'uninstructed' deviations in real-time from their schedules, *i.e.,* for producing or taking a different amount of energy in real-time than was scheduled without direction or permission from the [ITP.]" It also asks whether the increased costs of ancillary services or ramping capability (assuming it could be priced) that are necessitated by uninstructed deviations should be imposed on the entities that deviated from their schedules. Finally, the NOPR seeks comments on whether the SMD Tariff should include penalties for uninstructed deviations that threaten reliability and, if so, how such penalty provisions should be structured.

When the NYISO began operations, it uniformly imposed penalties for any uninstructed deviation. Over time the NYISO discovered that this system was unnecessarily harsh and gave suppliers undesirable incentives to undergenerate and to avoid being dispatchable. On the other hand, the NYISO concluded that it could not eliminate penalties entirely without jeopardizing reliability. The NYISO struck a balance by adopting penalties for "persistent" undergeneration by non-Regulation suppliers, providing that no supplier would be paid for inefficient, uninstructed overgeneration and by developing an incentive system to encourage efficient performance by Regulation suppliers.[121] This approach has resulted in significant performance improvements.

The NYISO does not administer a ramping "market" and does not believe that it is necessary to create one. It is not even clear how ramping service could be priced. Thus, it is not clear whether ITPs could directly assign ramping costs to entities that cause them by deviating from schedules and, at least at present, there seems to be little benefit in requiring them to do so.

ITPs should instead be given an opportunity to develop uninstructed deviation rules that would meet their needs given the specific resource mix within their regions. Because this is not an area where a one-size-fits-all approach will bring benefits or avoid market seams, the Commission should allow for regional variations Regions with ample surplus energy and transmission capacity may be able to rely entirely on incentives and do away with penalties. Regions facing tighter supply conditions may need strong penalties.

Finally, the NYISO's position with respect to real-time self-supply of ancillary services[122] is the same as its position regarding day-ahead self-supply. SMD should support self-supply but should allow ITPs to use financial, instead of physical arrangements.[123]

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121 *See* Letter Order in Docket No. ER01-2251-000 dated October 3, 2001.

122 *See* NOPR at P 325.

123 *See* Section VIII.H above.

K. Pricing "Lumpy" Generators

The NOPR expresses concern about the potential pricing inefficiencies, predominantly in the RTM, of excluding "lumpy"[124] generators from setting prices.[125] It proposes to allow a lumpy generator to set RTM prices if: (i) its output is needed to meet load during the hour in question; and (ii) it is not being run solely to meet a minimum run time constraint. The NOPR also states that less expensive generators, which must be backed down to make way for lumpy units, would be paid their lost opportunity cost as compensation for following dispatch instructions.

The NYISO has extensive experience dealing with "fixed block units," which are a subset of lumpy generators with operating characteristics that require them to either be turned off or to run at maximum output.[126] It has not been easy to develop rules that allow fixed block units to run when needed, to set prices when appropriate under LMP theory, and to ensure that more efficient units backed down to make way for them are properly compensated. The NYISO needed two years to create a "hybrid" that worked satisfactorily for New York.[127] These rules carefully balance many different considerations, some of which are unique to New York. Slight changes to the rules could produce unexpectedly disruptive effects on pricing, reliability, and market power mitigation, or lead to gaming.

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[124] "Lumpy" generators are units that can adjust their output on an hourly basis, but only in increments greater than 1 MW.

[125] NOPR at P 318.

[126] In New York, "fixed block units" are generally relatively high-cost gas turbines located in New York City or on Long Island.

[127] The Commission has dealt with various facets of fixed block pricing in a series of orders. *See, e.g., N.Y. Indep. Sys. Operator, Inc., Letter Order*, 100 FERC ¶ 61,182 (2002) (accepting proposal to let fixed block units set DAM prices); *N.Y. Indep. Sys. Operator, Inc.,* 99 FERC ¶ 61,126 (2001) (conditionally accepting certain fixed block pricing revisions).

Based on its experience, the NYISO believes that the NOPR's lumpy generation proposal is overbroad and should not be a required part of SMD. Standardization is not desirable in this area because different regions will have region-specific requirements. This is an area where inefficient rules are especially likely to have significant adverse effects.

Under the current NOPR definition, lumpy generators will usually be more flexible than fixed block units and will have less need for special pricing accommodations. Nevertheless, the NOPR's pricing proposal would make it necessary to develop complex, region-specific rules to govern them. The greater numbers and diversity of lumpy generators would make it harder for ITPs to develop efficient rules than it was for the NYISO to deal with fixed block units. The broader scope of the rules would also make it more difficult to determine whether the rules were creating perverse incentives, and when (or what) changes were needed.

Special lumpy generator pricing rules should thus be narrowly tailored so they apply only when the need outweighs the difficulty of creating and administering them. This may mean that regions without significant lumpy generation do not adopt special rules while regions, like New York, which has a substantial amount of fixed block generation, develop special rules for them without addressing lumpy generators more generally.

L. Market Rules for Shortages or Emergencies (PP 326 - 327)

The NYISO strongly supports the NOPR's proposal to give ITPs the same authority to curtail transmission, and take any other action necessary to preserve system reliability in emergencies, that Order No. 888 currently provides. While the NOPR is probably correct that the introduction of SMD markets and more extensive demand-side participation will lessen the need to invoke emergency procedures, it would not be wise to assume that they will never be needed.

The NOPR also observes that reliability actions can have price implications and asserts that market participants should have advanced knowledge of what the economic effects will be.[128] It therefore requires ITPs "to file proposals with the Commission regarding the implications for market pricing of each reliability procedure"[129] and seeks comments on whether more specific requirements should be imposed.

The NYISO tariffs and manuals already specify how it will calculate prices in the event that it must resort to common emergency procedures. This practice ensures that market participants have a reasonable opportunity to anticipate the foreseeable economic consequences of likely emergency actions. Moreover, the rules are evaluated by the NYISO's Independent Market Advisor and will be revised if necessary to ensure that they do not prevent energy prices from efficiently reflecting shortage conditions. ITPs could adopt a similar practice.

The Commission should not require ITPs to go beyond disclosing emergency pricing methodologies. Based on the limited experience of the current wholesale markets with these types of pricing rules, it would be difficult to impose more specific requirements without a significant risk of introducing unintended market effects. ITPs should be permitted to take extraordinary emergency actions when necessary, even if the ITP has never made a filing concerning the price effects of a particular action because it never anticipated having to use it. A rule that prevented this could tie an ITP's hands at a critical moment and jeopardize the reliability of the system.

Finally, as was noted above in Section _, certain market participants believe that the Commission's existing RTM pricing rules do not adequately compensate generators during

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128 NOPR at P 327.

129 *Id.*

emergency or scarcity periods. The NYISO is studying this issue. The final rule should be sufficiently flexible to allow ITPs to adopt any necessary scarcity pricing rules.

IX. OTHER CHANGES TO IMPROVE THE EFFICIENCY OF THE MARKETS UNDER SMD (PP 328 – 369)

A. Capacity Benefit Margin and Transmission Reliability Margin (PP 330 - 332)

The NOPR proposes to "standardize" the treatment of Capacity Benefit Margin ("CBM") to prevent alleged abuses by transmission providers that have made transmission capacity unavailable in the name of generation reliability.[130] The NYISO does not use CBM in the allegedly abusive manner that the SMD describes and does not believe that such abuses should be allowed. The NYISO therefore does not object to the NOPR's proposal which would essentially treat CBM reservations like any other transmission reservation. The NYISO also agrees with the distinction the NOPR draws between CBM and Transmission Reliability Margin set-asides, which should continue to be allowed.

B. OASIS Standards (PP 333 – 334)

The NYISO supports the NOPR's regional OASIS proposal. Although the NOPR does not mention the issue, the Commission should ensure that all of the OASIS standards established under Order Nos. 888 and 889, which were designed with physical transmission reservations in mind, are up to date and fully compatible with NAS.[131] All indications are that the Commission supports the ongoing efforts by the Electronic Scheduling Collaborative ("ESC") and OASIS Standards Collaborative ("OSC") to conform OASIS to SMD, and expand the scope of OASIS to

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[130] NOPR at P 331.

[131] Because the physical standards are fundamentally inconsistent with NAS, the NYISO has previously had to obtain waivers of several OASIS requirements in order to operate its financial reservation system. *N. Y. Indep. Sys. Operator, Inc.*, 94 FERC ¶ 61,215 (2001).

encompass other data transfers. It would be helpful for the Commission to formally endorse these initiatives in the final rule.

C. **Modular Software Design (PP 351 – 360)**[132]

The NYISO supports the NOPR's software proposals, including especially its establishment of transparency, testability and modularity principles. Scalability, security and robustness are essential software design features. The NOPR is also right to seek to standardize software, data and communications systems without giving rise to vendor monopolies.

The NYISO does not agree with the NOPR's assertion that "for most applications, software does not appear to be a binding constraint on the size of RTOs or the implementation of [SMD]."[133] The NYISO's experience indicates that the computational demands of administering super-regional markets may well exceed the capabilities of existing software and hardware systems. This is especially likely to be the case if software and hardware systems must accommodate the full range of features proposed in the NOPR. As was noted above in Section VIII, certain NOPR market design components may take a long time to implement using existing technologies, even in market the size of New York. The Commission must not simply assume that "software and associated hardware needs" will "keep pace with market span."[134] Instead, it should take a realistic approach and not put unreasonable pressure on ITPs to introduce features that are not feasible, or that have significant development and implementation costs relative to their likely immediate benefits.

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[132] In addition to the views expressed herein, the NYISO also supports the position of the *Joint Comments* on these issues.

[133] NOPR at P 356.

[134] *Id.*

The NOPR expresses a preference for the "standardization approach" over the "open systems approach" to facilitating data transfer between modules. It seeks comment on whether it should look to the NAESB process, the Electric Power Research Institute ("EPRI") or some other vehicle to establish the needed standards.

Because ITPs will have the best understanding of their software capabilities, and will be responsible for making their software work, they must play the leading part in creating software standards. They could do this through an ITP organization. NAESB's members should not drive the software development themselves because there are too many technical issues for a large consultative process to be effective. NAESB participants will also not have the same expertise as ITPs, but will have commercial interests that influence their positions. EPRI can be a useful resource to support the ITPs but should not supplant them.

The Commission should press for the establishment of standards in a few areas where they will provide clear and immediate benefits. First, there should be standards to govern the operation of bidding and scheduling interfaces during non-emergency market operations. Standardized interfaces would make it easier for third parties to develop software that will increase the efficiency of both ITPs' and market participants' market operations.

Second, the Commission should back EPRI's initiative to extend the Common Information Model ("CIM") to encompass market data, but should not allow the initiative to expand into other areas. Data standards will help vendors, including those that have not worked on electric utility applications in the past, to develop software and accelerate market development. The Commission should also facilitate the development of a common understanding of how ITP market applications can be modularized. Such an understanding, coupled with CIM data standards, will facilitate greater third party involvement and more rapid software improvements.

Third, the Commission should consider establishing standardized auditing requirements. Existing ISOs and RTOs are trying to establish data requirements that will support SAS 70 and other audit processes, but their efforts have been hindered by the speculative nature of the task. Commission-established standards would facilitate these efforts.

At least initially, the Commission should adopt the "open systems" approach to all other aspects of system design. Openness is preferable in areas where standards are not needed immediately because it will allow efficient standards to evolve naturally. The Commission should not prescribe software standards in areas where the need for them is not urgent because there is a significant risk that it might inadvertently stifle innovation or give a particular vendor an unfair advantage.

E. Transmission Facilities that Must Be Under ITP Control (PP 361 – 369)

The NOPR proposes to adopt a new presumption that any facility that is not found to be local distribution facility under Order No. 888's seven-factor test should be under ITP control.[135] This is a more expansive test than the Commission used to assess the adequacy of ISOs' operational authority in Order No. 888, or RTOs' in Order No. 2000, and it goes too far. The NYISO has several years of experience operating efficient SMD-type markets. It has been successful even though it does not have operational authority over a number of facilities that the seven-factor test would classify as transmission. The same is true, albeit perhaps to varying degrees, with other existing ISOs. There will thus often be little or nothing to gain from insisting that ITPs control every facility that arguably performs a transmission function in their region.

[135] NOPR at P 367.

At the same time, Transmission Owners may have legitimate reasons for retaining control over certain transmission facilities. For example, New York City has a very sophisticated and (in some places) fragile underground electric transmission system that is closely linked with the local distribution system. As a result, the NYISO has always shared certain security coordination and monitoring functions with the local transmission owner. This arrangement has worked well. The final SMD rule should be sufficiently flexible to preserve these kinds of relationships. An overly inflexible approach could cause transmission owners to resist transferring control to an ITP. There could be litigation, and SMD implementation delays, if the Commission attempts to force transfers, or refuses to certify otherwise qualified ITPs. When control of facilities will have no significant impact on an ITP's ability to fulfill its core responsibilities, and will not provide Transmission Owners with an unfair competitive advantage, it is not worth potentially delaying the implementation of SMD over them.

The NYISO therefore recommends that the Commission either drop the NOPR's presumption or, at a minimum, not allow it to become unreasonably difficult to rebut. In either case, the Commission's focus ought to be on whether an ITP has sufficient operational authority to provide efficient open-access service and administer efficient SMD markets. Under this standard, existing ISOs with functioning markets might not need to control any additional facilities to become ITPs.

The NOPR also seeks comment, at P 369, on "whether, either in addition to or in lieu of the seven factor test, the Commission should use a bright line voltage test (*e.g.*, 69 kV) to determine which facilities are placed under the control of the [ITP]." A bright line voltage test does not solve the issues previously addressed in these comments and should not be included in the final rule. As was noted above, the Commission should instead focus on whether ITPs have the authority they need to successfully implement the SMD.

X. TRANSITION TO SINGLE TRANSMISSION TARIFF (PP 370 – 389)

A. Regional Flexibility (P 371)

The NYISO strongly supports the NOPR's proposal to allow regional flexibility with respect to the conversion of existing transmission rights into CRRs or auction revenues and ITP rate design. These are areas where having different rules in different regions will not create market seams and where insisting on absolute uniformity would be inefficient and controversial. As is noted below, the same is true regarding the treatment of existing wholesale contracts and CRR allocations in regions that have previously addressed these issues. The Commission should be flexible in these areas as well. In particular, the Commission should defer to existing ISOs and RTOs that have already resolved these issues and whose market participants have made financial decisions based on those resolutions.

B. Treatment of Existing Wholesale Contracts (PP 372– 375)[136]

The NYISO supports the NOPR's proposal to allow pre-Order No. 888 transmission contracts to continue, if their parties so desire, within the SMD framework. The NYISO has successfully accommodated a number of grandfathered contracts since the inception of its NAS model in 1999. It has also managed the conversion of a number of agreements from grandfathered service to NAS service. Future ITPs should have the ability to craft similar agreements with their customers.

[136] In addition to the views expressed herein, the NYISO also supports the position of the *Joint Comments* on these issues.

More generally, the Commission should recognize that many ISO regions have either developed a consensus or settlement approach to grandfathered contracts or, where the settlement process has failed, engaged in litigation.[137] The Commission should permit those regions to retain their current practices without imposing any new or inconsistent requirements.

C. Allocation of Congestion Revenue Rights (PP 376 – 382)[138]

The NOPR proposes a standardized methodology, with some allowances for regional variations, to govern the initial allocation of CRRs and seeks comments on it. The NOPR does not indicate whether regions that have already allocated CRR-like instruments, such as the NYISO which conducted its initial TCC allocation several years ago, must undertake a new "initial" allocation of CRRs using the NOPR's rule. Undoing allocations that were previously approved by the Commission and requiring parties to start over would serve no useful purpose. The original allocation will have already accomplished the NOPR's objectives of preserving customers' pre-LMP service rights, providing access to all available capacity and minimizing cost-shifts. Moreover, a second "initial" allocation would disturb long-settled economic expectations and could result in controversy and litigation. The final rule should therefore clarify that regions that have already allocated CRR-like instruments are not required to re-do those allocations

D. Reciprocity (PP 383 – 384)

The NYISO supports the continued application of the Order No. 888 reciprocity rule to non-jurisdictional transmission owners and agrees that existing Order No. 888 reciprocity tariffs should be grandfathered. The Commission should continue to encourage non-jurisdictional

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137 *See, e.g., Central Hudson Gas & Elec. Corp.*, 100 FERC ¶ 61,023 (2002).

138 In addition to the views expressed herein, the NYISO also supports the position of the *Joint Comments* on these issues.

transmission owners to participate in ISOs, RTOs and ITPs to the greatest extent possible[139] and should modify its reciprocity rule when necessary to secure their participation. It should also strive to find ways to address the jurisdictional and tax issues that their participation can create.

Finally, the Commission should maintain its current flexible approach to evaluating what constitutes comparable transmission service in the case of Canadian system operators.[140] This is especially important to the NYISO's efforts to establish a "common market" across the Northeast Power Coordinating Council ("NPCC") which will probably require the Commission to allow the Canadian NPCC control areas to depart from the Commission's SMD and NAS standards in certain ways.

E. Force Majeure, Indemnification and Limitations on Liability (PP 385 – 389)[141]

The NYISO supports the inclusion of force majeure language and indemnification provisions in the SMD tariff. The Commission should revise the force majeure provision to include acts of terrorism, which will make it easier for ITPs to obtain insurance, and clarify that "breakage or accident to machinery or equipment," includes catastrophic market software failures. It should also specify that customers will indemnify ITPs except in cases where an ITP engages in gross negligence or intentional wrongdoing.[142]

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139 The Commission's efforts were successful in New York, where special arrangements have permitted the Long Island Power Authority and New York Power Authority to participate fully in the NYISO.

140 *TransAlta Enter. Corp.,* 75 FERC ¶ 61,268 at 61,875 (1996). *See also, Energy Alliance Partnership,* 73 FERC ¶ 61,019 at 61,030-31 (1995); *Ontario Hydro Interconnected Mkt., Inc.,* 78 FERC ¶ 61,369 at 62,528 (1997).

141 In addition to the views expressed herein, the NYISO also supports the position of the *Joint Comments* on these issues.

142 The NYISO does not disagree that transmission owning utilities that participate in ITPs should also be indemnified, to the extent permitted by applicable state law.

The NOPR seeks comments on a number of liability issues. Specifically, it asks:

> Is there a need to include liability provisions in the Commission's *pro forma* tariff? Under what circumstances should liability protection be provided in a Commission open access transmission tariff (*e.g.,* should we provide such protection only where it is not available through state tariffs? If we adopt liability provisions should they be generic or do they need to be adopted on a regional basis? Should the standards adopted in the Commission *pro forma* tariff reflect what was previously provided under state law? How do we resolve the issue in the multi-state context of an ISO or RTO."

The Commission subsequently announced that it would hold a technical conference on December 11, 2002 to address ITP liability and indemnification under the SMD Tariff.

The NYISO believes that the Commission should include extensive liability protections in the SMD tariff that should be applicable to all services provided under the tariff and all claims by third parties. The Commission has recently accepted the inclusion of limitations on liability provisions in the MISO's open access transmission tariff.[143] It should afford even stronger protection to ITPs because they will have greater market-administration responsibilities, and thus be exposed to greater liability, than the MISO is as the operator of pre-SMD markets. The SMD tariff should explicitly limit the liability of ITPs, except when they are liable for gross negligence or intentional misconduct. Regardless of the standard of care adopted by the Commission, the tariff should also make it clear that the ITP is not liable, under any circumstances, for any special, indirect, incidental, consequential or punitive damages.

Several state commissions have recognized with regard to state tariffs that limited liability provisions avoid cross-subsidization of risks, excessive damages awards, and incentives to either overbuild or underutilize the system. The proposed limits would also advance Commission policy, by reducing (and limiting) the risks of participating in an ITP or RTO.

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[143] *Midwest Indep. Transmission Sys. Operator, Inc.*, 100 FERC ¶ 61,144 (2002).

The SMD tariff's liability provisions should not be limited to situations where protection is unavailable through state tariffs. Any protections under state tariffs may not be applicable to Commission-jurisdictional transmission service. State tariff protections will clearly not be available to RTOs, ISOs and ITPs that do not have state tariffs in the first place. It would also be inappropriate to permit states to influence ITP rates, which should be exclusively Commission-jurisdictional, through their liability policies. Thus, limitation of liability language, similar to that available to most integrated utilities under state law, should be provided in the SMD tariff.

Without liability limitations, ISOs, RTOs, and ITPs could be exposed to millions of dollars in potential damages for service interruptions. That liability would translate into higher rates from higher insurance costs, if such insurance is available at all.[144] Higher rates would also result if insurance coverage is inadequate and to the extent damage claims passed through to customers.[145]

States such as Texas, Pennsylvania and Maryland that have analyzed liability limitation provisions have concluded that they benefit ratepayers because the costs of insurance are less than the rate increases they would bear absent the liability protections.[146] This relationship is likely to be equally true for RTOs, ISOs and ITPs.

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144 The Commission should not assume that insurance is readily available at a reasonable price. Where insurance is available, it is becoming increasingly expensive.

145 If ITPs that are not-for-profit entities cannot pass these costs through to customers, bankruptcy will be the likely outcome.

146 *See Midwest Indep. Transmission Sys. Operator, Inc., Section 205 Revisions to Open Access Transmission Tariff,* Attachment 3, "Affidavit of Richard J. Pierce, Jr. on Behalf of Midwest Independent Transmission System Operator, Inc. and American Transmission Company LLC.," Docket No. ER02-2033-000 (June 5, 2002).

XI. MARKET POWER MONITORING AND MITIGATION IN ITP MARKETS (PP 390 – 456)

The NYISO agrees with the NOPR's ultimate goal of developing "structurally competitive" markets that do not require extensive market power mitigation.[147] The NOPR is also correct to find that electricity markets have not yet reached that stage and that vigilant market power monitoring and mitigation will continue to be necessary for some time. Moreover, conditions that create significant congestion, and hence significant potential for market power abuse, can arise from time to time even in markets that generally are structurally competitive.

The NYISO has been a national leader in this area. It has created a comprehensive market power monitoring and mitigation system that has successfully prevented the kinds of abuses that have occurred in other markets, without inhibiting market efficiency.[148] The NYISO's model has influenced other regions,[149] and the Commission has found that its core principles are "generally consistent with the approach laid out in the SMD NOPR."[150]

Based on its experience in developing its system, the NYISO believes that the NOPR includes a number of good proposals. Experience also suggests, however, that several aspects of the NOPR should be modified, mostly in order to allow greater flexibility and to preserve the availability of successful mitigation tools that already exist. The Commission must also resist

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147 NOPR at P 390.

148 *N. Y. Indep. Sys. Operator, Inc.,* 99 FERC ¶ 61,246 (2002); *California Indep. Sys. Operator Corp.,* 100 FERC ¶ 61,060 (2002). *See also, Compliance Filing of the New York Independent System Operator, Inc. Regarding Comprehensive Market Mitigation Measures and Request for Interim Extension of Existing Automated Mitigation Procedure,* Attachment VI, Affidavit of Dr. David B. Patton, PP 42-53, filed Mar. 20, 2002.

149 *See New England Power Pool and ISO New England Inc.,* 100 FERC ¶ 61,287 (2002) (accepting ISO-NE market power monitoring and mitigation tools similar to the NYISO's); *Cal. Indep. Sys. Operator, Inc.*, 100 FERC ¶ 61,060 (2002) (accepting a California ISO mitigation proposal modeled on the NYISO's AMP).

150 100 FERC ¶ 61,287 at P 41.

the competing pressure it will face to either prematurely terminate effective mitigations or to over-mitigate in a way that artificially suppresses scarcity price signals.

A. <u>The Commission's Definition of Market Power (P 393)</u>

The NOPR defines "market power" as the "ability to raise prices above the competitive level."[151] The NOPR recognizes that market power can develop (and disappear) quickly and be hard to detect in electricity markets. The Commission appears to understand that market power in electricity can be subject to significant abuse in much shorter periods than is generally typical of other markets. The NYISO supports the proposed definition.

In electricity markets, participants can produce noncompetitive outcomes during relatively short periods of time through either economic or physical withholding. Such behavior may warrant mitigation, even when it is limited to relatively brief periods, because the magnitude of electricity price increases that can occur in those periods substantially exceeds the potential price increases for most other products.

The NOPR expresses some concern that "cost of intervention in transient price increases could be greater than the public benefit gained by the intervention . . . ." The NYISO agrees with this concern and has addressed it by employing bright-line mitigation thresholds that only allow mitigation when clear instances of economic withholding are resulting in large price increases. Well-designed mitigation tools that employ these types of thresholds can identify and address significant short-term abuses of market power without disrupting the markets or muting scarcity price signals.[152]

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151 NOPR at P 393; fns. 195 and 196.

152 The NYISO's market power mitigation screens, discussed below, have these characteristics.

Market monitoring plans should also establish an expedited process for market monitoring units ("MMUs") to seek Commission action when market power abuses cannot be remedied through mitigation.

B. Market Power Mitigation Measures (PP 399 - 428)

1. Participating Generator Agreements (PP 399, 406 - 412)

The NOPR would require all suppliers that are dispatched by an ITP to enter into "participating generator agreements" ("PGAs") that would "include provisions to mitigate local market power."[153] The primary mitigation measure to address local market power would be a unit-specific bid cap, coupled with a must-offer requirement, the specific provisions of which would be contained in each generator's PGA. As an initial matter, the NOPR mistakenly implies that the NYISO currently uses PGAs.[154] In reality, PGAs are not used or needed in New York but could be accommodated if the Commission requires them. As the NOPR proposes, the primary mitigation measure employed by the NYISO is a unit specific bid cap, referred to as a "default bid measure" in the NYISO's market mitigation plan.

The NYISO's bid cap measure uses a series of conduct and market impact screens to determine whether suppliers are engaging in significant market power abuse. The screens are set at levels that limit mitigation to significantly non-competitive bidding that has a relatively large effect on market prices. If a supplier's bids trigger both screens and the supplier cannot demonstrate that its bids were justified, then its bids will be reset to a reference level based on its recently submitted competitive bids, or a reasonable proxy if no competitive bid history is available. A mitigated supplier will still be eligible to receive the market-clearing price.

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153 NOPR at P 407.

154 NOPR at P 407.

Because the NYISO's default bid measure is applied in the same manner to all suppliers, although suppliers in known load pockets are generally subject to lower thresholds, there is no need to embody these provisions in PGAs that are specific to each supplier. However, if the Commission requires the use of PGAs, it should clarify that standardized PGAs for suppliers in New York, or other regions with comparable mitigation needs, would contain the same conduct and impact thresholds for all similarly situated units (*i.e.*, all units located in the same load pocket). Regions with different needs could adopt PGAs with different substantive contents.

Further, if the Commission requires the use of PGAs they should not be structured as "must-run contracts" like those that have been used to address local market power in other regions. Rather, the Commission should provide specific guidance on PGA terms or consider adopting a *pro forma* PGA. The NYISO's understanding is that ISOs in regions that employ must-run contracts have often had great difficulty negotiating them because suppliers have no incentive to agree to restrictive mitigation terms. Clear Commission policy guidance would reduce the time and resources ITPs would have to devote to PGAs and avoid deadlocks. The NYISO supports the *pro forma* PGA that is appended to ISO-NE's comments in this proceeding.

2. Forced Outage Risks (P 412)

The NOPR discuses three options for the "dealing with the risk of a forced outage inside a load pocket" and seeks comment on the penalty that would be appropriate to deter unjustified forced outages. The NYISO does not believe that any of the three options are necessary, or appropriate, because SMD, and the conduct-impact mitigation framework, already address the underlying problem in several ways.

First, the conduct and impact thresholds allow participants to raise their bid prices to reflect forced outage risk and not face the potential for mitigation. Second, since the reference prices to which suppliers are mitigated are developed based on previously accepted competitive bids, the reference prices themselves will reflect these risks. Additionally, these reference prices may also be adjusted by the MMU if the risk is justified and cannot be hedged by the participant.

Last, the NOPR proposes allowing virtual purchases and sales in the DAM (purchase and sales of power that are not associated with physical generation or load that would be settled in the RTM). A supplier making a virtual purchase at its location in the DAM would be able to fully hedge the risk of a forced outage without physically withholding.

Therefore, the NYISO would advise the Commission not to propose any explicit exemptions for physical withholding or provisions that would hold a supplier harmless for a forced outage. Such exemptions are not necessary, could create inefficient incentives and might result in gaming.

3. The Safety Net Bid Cap (PP 413 – 414)

The NYISO supports the Commission's safety net bid cap proposal. It is important to have a consistent bid cap across regions that transact with each other. This will prevent gaming, such as the "megawatt laundering" that occurred in the West, and avoid making a region with a lower cap artificially attractive to potential suppliers. The NYISO therefore would support the adoption of a single bid cap for the Eastern Interconnection and another cap for the Western Interconnection.

The NOPR seeks comment on how to determine the appropriate value for a bid cap.[155] The NYISO believes that the $1,000 cap currently in effect in the Northeast is a good starting point for the Eastern Interconnection. Although the level of the cap was not based on an economic study and was set at $1,000 to match the cap in neighboring regions, it has proven to

[155] NOPR at P 414.

be an effective "damage control" device given the current weakness of demand response. If the Commission decides to establish a different cap, it should set it at a level higher than the marginal cost of the least efficient supplier that will be subject to it.

It would be appropriate for the Commission to develop a set of rules that would gradually phase safety net bid caps out as demand response mechanisms improve. If the Commission decides to pursue such an initiative, it would be helpful to begin by holding a technical conference.

4. "Mitigation Triggered by Market Conditions" (PP 415 – 417)

The NOPR proposes that MMUs be permitted to adopt an additional "voluntary" mitigation mechanism which would apply to "unanticipated and sustained market conditions that would give the ability and the incentive to exercise market power."[156] Examples of such conditions include "non-transitory conditions" characterized by "extreme supply or demand conditions to which the market cannot quickly adopt, such as the loss of significant hydropower capacity because of drought, or force majeure events such as a major transmission line outage."[157] The NOPR indicates that the NYISO's automated mitigation procedure ("AMP") is the model for the "voluntary mechanism," but emphasizes that it should be a "temporary" tool. It therefore proposes that MMUs which propose to use AMP-like measures must propose specific tariff "triggers" that would activate, and deactivate, them as market conditions change.

The NYISO is concerned that this proposal reflects a misunderstanding of the NYISO's AMP. The AMP is not a separate mitigation mechanism. It is simply the name for the software tool that automates the conduct and impact thresholds that indicate when mitigation is warranted.

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156 NOPR at P 415.

157 *Id.*

The mitigation that is triggered by this software is consistent with the NOPR's bid cap provisions.

The NYISO automated this system in order to prevent the artificial delays in this imposition of mitigation measures inherent in the manual application of mitigation to fast-moving electric markets. In addition, automation makes the triggering of mitigation much more accurate because it is occurs based on conditions in a current period, rather than relying on analysis of a past period, to determine whether mitigation is warranted.

By making the AMP a "temporary" measure, the NOPR would effectively prevent MMUs, including the MMU responsible for New York, from using a system that has proven well-suited to New York's SMD-based markets. It would likewise prevent MMUs in other regions from adopting this type of system.

The fact that these mitigation mechanisms are rarely invoked[158] does not mean that they should be "temporary." Rather, it provides evidence that the conduct and impact thresholds effectively limit intervention in the market to times when evidence of a substantial abuse of market power exists. It also shows that the conduct and impact approach is inherently self-limiting because it will automatically apply less often as market power diminishes and bids cease to trigger the conduct and impact screens. This is consistent with the Commission's goal of phasing out market power mitigation as market structure problems are resolved.

Therefore, the Commission should encourage the use of the conduct and impact thresholds for triggering mitigation. ITPs should have the option of developing automated tools. There is no reason to formally restrict the use of these tools to unusual market conditions because, by definition, they will only apply in appropriate situations.

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[158] *See* NOPR at n. 206 (noting that the AMP only triggered on four occasions).

In addition, the final rule should permit appropriate conduct and impact mitigation to be used without being limited to geographic areas designated in advance. "Appropriate" conduct and impact thresholds for such general use would be set at levels, as in the NYISO, that are very unlikely to be reached except as a result of an abuse of market power. At the same time, the final rule should authorize application to be made to the Commission for the use of more stringent conduct and impact thresholds in specific areas in which persistent structural market power problems make mitigation at lower conduct and impact mitigation appropriate.

This approach has worked well in New York, where relatively high conduct and impact thresholds apply statewide, but lower levels have been approved for use in New York City, which has been specially designated as a "Constrained Area" because of the particular market power situation that exists there. It also recognizes that in electric markets, a relevant market for market power analysis can be a short as an hour, and that relatively low market power price increases that can be sustained over longer periods or relatively sharp price increases that can be imposed only for shorter periods can have the same dollar impact on electricity consumers.

Consequently, consistent with the discussion in Section B.1, MMUs should have the flexibility to adopt bidding conduct and price impact screening systems, automated or otherwise, instead of PGAs, or PGAS that are consistent with conduct and impact mitigation, as their primary mitigation tool.

5. Establishing Bid Caps or Competitive Reference Bids (PP 418 – 427)

Based on its experience, the NYISO believes that it will normally be best to establish each supplier's reference bid level by looking at its recent history of bids accepted during periods when it was not able to exercise market power. The NYISO has successfully used this method under its conduct and impact system, but its advantages would be equally applicable under an appropriate PGA regime. It is not difficult to administer, and allows reference bid levels to be adjusted quickly as key conditions, *e.g.,* fuel prices change. It is also more efficient and accurate than alternative systems that rely on cost-based measures or negotiation to set reference bid levels. Appropriate alternative measures of establishing reference bids will be needed for situations when a sufficient history of competitive bids is not available, but the use of past competitive bids should always be the preferred alternative.

The Commission should therefore endorse the use of market-based reference bids instead of requiring ITPs to base default bids on estimates of operating costs plus an arbitrary margin. Accepting this method would obviate the need to calculate a special "scarcity premium" for peaking units[159] (assuming that they will continue to be eligible to receive capacity payments and bid sufficiency guarantees) or special reference bid rules for ELRs.

The NOPR seeks comments on whether bid caps should apply to market-based ancillary services.[160] The NYISO believes that this is appropriate, because energy and ancillary services will be co-optimized under SMD. The interdependence of energy and ancillary service bids means that a participant with market power in the energy market could extend it into the ancillary services markets. Similarly, reference levels based on competitive bid histories can be applied to any "bid-in operating parameters," such as start-up, no load, low and high operating limits and minimum run times.[161]

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159 *See* NOPR at 421.

160 NOPR at P 424.

161 *See* NOPR at PP 425-26.

6. Exemptions (P 428)

The NOPR seeks comment on whether particular types of sellers should be generically exempted from mitigation because they lack the ability or incentive to withhold. Exemptions are generally not necessary under a conduct and impact test based mitigation system because sellers that are not in a position to exercise market power will not be mitigated under it. Administering a system of exemptions would be difficult, and would require the imposition of a static system of exemptions on dynamic and rapidly changing markets. As a result, an exemption system could create opportunities for gaming, and give sellers inefficient incentives to behave in ways calculated to qualify for exemptions. Limited exemptions in specific situations may, however, be appropriate. For example, the NYISO's AMP exempts sellers, or a group of affiliated sellers, with less than 50 MW of generation exceeding the conduct thresholds from automated mitigation because withholding at such low levels is sufficiently unlikely to reflect an exercise of market power as to make automatic mitigation not warranted. At the same time, there should be provisions to remove the exemption if experience shows that market power abuse is in fact occurring at such low levels of withholding.

C. Market Monitoring Unit Structure (P 429)

The NOPR proposes that each region have an MMU that is "autonomous" from the ITP's management and from market participants. MMUs may be located within an ITP's offices or may be located elsewhere and must report to both the ITP Board and the Commission.

The NYISO strongly supports the NOPR's proposal that MMUs be autonomous from market participants. In the last few years, various market participants have proposed MMU structures that would be subject to their influence or control. Such arrangements are obviously inappropriate, would seriously undermine the effectiveness of market monitoring, and should never be allowed by the Commission.

The NYISO likewise does not object to making the MMU autonomous from ITP management and strongly supports having the MMU report to the ITP Board. Because ITP Boards are responsible for the ultimate success of ITP markets, rather than their daily administration, they will not have an incentive to pressure the MMU to exaggerate the ITP's successes or downplay its failures. There is thus no reason to insist that MMUs be independent of and segregated from ITP Boards. Conversely, it would be advantageous for an ITP Board to have a close relationship with an MMU since it would ensure that the Board receives accurate information, understands critical problems and makes well-informed decisions. MMUs would benefit from the Board's support, and from the Board's ability to ensure that they have immediate access to ITP data and the full cooperation of ITP staff.

The Commission should also clarify that ITPs may employ staff to perform administrative market monitoring-related functions that complement the MMUs' activities. ITP employees can efficiently collect data for the MMU's use or implement mitigation decisions that the MMU makes. Allowing such employees to remain under the control of ITP management does not create the concerns that led the Commission to require that MMUs be autonomous. It will also enable MMUs to avoid hiring large support staffs to replicate tasks that ITP staffs are already handling.

Finally, the NOPR does not address whether an ITP may divide market-monitoring responsibilities between an internal monitoring staff and an external MMU. In the Joint Petition, ISO-NE and the NYISO have proposed that the NERTO have both an internal market monitoring staff, that would perform non-discretionary functions, and an independent external MMU.[162] The Commission should clarify that this arrangement is consistent with its policies. The premise behind this arrangement is that the two entities will have complementary advantages and a diversity of perspectives that will make them more effective together than a single entity would be alone.[163] This structure is consistent with the current market monitoring practices in California, New York, and New England that each have an independent external component of their market monitoring function. To the extent that market monitoring will include monitoring ITP activities as discussed below, the importance of the independent external component is increased.

D. <u>Market Monitoring Unit Reports and Audits (PP 430 – 434)</u>

The NYISO generally agrees with the NOPR's proposals in this area. It is appropriate for MMUs to submit reports to the Commission and to ITP Boards simultaneously. MMU reports should also be shared with ITP management and with interested state regulators. MMUs should be responsible for monitoring, and when necessary mitigating, both generation and transmission owners (including ITCs).

The NOPR seeks comments on whether MMUs should be responsible for monitoring ITP operations, in addition to market participants and the markets, including whether the ITP treats market participants impartially.[164] As is proposed in the ISO-NE/NYISO Joint Petition, MMUs

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162 The Commission recently indicated that it would allow the WestConnect RTO to adopt a structure that appears to allow RTO management greater authority over market monitoring. *See Arizona Public Service Co., et al.*, 101 FERC ¶ 61,033 at PP 181, 188 – 192 (2002) (accepting a market monitoring proposal under which WestConnect's CEO would oversee an internal MMU and the WestConnect Board would have the option to retain an outside independent market advisor).

163 *Joint Petition,* Section VI. D. PP 46-47.

164 NOPR at P 432.

should be responsible for monitoring an ITP's administration of its rules and procedures to ensure that they do not result in improper or inefficient market outcomes. If the Commission concludes that other operational audits of ITPs are necessary, they should be conducted by professional auditors, with oversight and review by the ITP Board.

The NYISO agrees with the NOPR's proposals regarding the importance of ensuring that MMUs have full access to market information.[165] It also supports the proposed sanctions that would apply to market participants that do not cooperate in MMU investigations.

E. Market Monitoring Methodology (PP 435 - 443)

The NYISO generally supports the NOPR's proposal to develop standardized market monitoring methodologies and reporting formats based on best practices. It also agrees that MMUs should be encouraged to expand their analyses beyond the "core" requirements when regional differences or unanticipated events warrant.[166] However, because the analytic approaches related to market monitoring continue to evolve, the Commission should avoid being overly prescriptive in this area. For example, the white paper prepared for the Commission's October 2, 2002 technical conference on standardized market monitoring and market monitoring metrics contained a much longer list of metrics than MMUs should be required to compute and report. The final rule should instead identify a limited number of required metrics that would serve as minimum reporting requirements, allowing flexibility for the MMU in other areas. Existing ISO and RTO MMUs are working collaboratively to develop a more appropriate list. The Commission should support this effort.

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[165] NOPR at PP 433, 447 - 450.

[166] *See* NOPR at P 436.

. The NOPR seeks comments on MMUs' role in developing useful metrics that will facilitate inter-regional market comparisons.[167] The NYISO believes that the Commission should encourage MMUs to exchange information and ideas with each other. In special circumstances, such as multi-MMU market power and gaming investigations, the Commission should allow MMUs to share confidential information.

Finally, the Commission should make it clear that ITPs must have comprehensive monitoring plans and monitor all classes of market participants, including transmission owners and demand resources, rather than focusing exclusively on generators. Transmission withholding, and gaming by loads, can pose serious problems that ITPs must address.

F. Market Power Assessments (PP 439 – 440)

The NYISO does not object to the NOPR's proposals requiring MMUs to conduct: (i) an initial market power assessment prior to SMD implementation; (ii) annual market power assessments every year thereafter to determine whether fewer, more, or modified mitigation tools are needed; and (iii) an annual performance assessment of each ITP-administered market. However, given the evidence that electricity markets are susceptible to market power abuses, even when SMD-like systems are in place, the Commission's review of these assessments should begin with the premise that effective mitigation tools are necessary. At least initially, the SMD should not require justification of mitigation of regions where proven mitigation tools are already established. Instead, the MMU, and any stakeholders that oppose mitigation, should have to make the case for relaxing mitigation without an ITP's support. There should be no rush to terminate "self-limiting" mitigation tools, such as the NYISO's conduct and impact system, since they will not be active during periods when market power problems do not exist.

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[167] NOPR at P 441.

G. Anti-Gaming Penalties and Enforcement (PP 445 – 446, 454 – 456)

The NYISO supports the NOPR's proposed penalties which should provide an effective deterrent against abusive behavior. Nevertheless, it will be important for the final rule to more precisely define which behaviors are forbidden in order to: (i) eliminate uncertainty regarding the scope of penalties; and (ii) avoid the possibility that justifiable behavior will be penalized. For example, the NOPR would prohibit physical withholding, but the proposed definition does not allow for the possibility that it may be economically justified for a supplier to place a unit on an extended outage if the costs of maintaining the unit exceeds the expected market revenues over the period.

The Commission and future MMUs must not be overly aggressive in imposing penalties, or they will run the risk of discouraging legitimate profit-maximizing behaviors. Instead, the emphasis should be on fixing any rules that permit gaming to occur in the first place.

To the extent that there are penalties, they should clearly apply to all classes of market participants. Transmission owners and, under certain conditions, loads can be presented with opportunities to exercise market power and should be deterred from taking advantage of them.

XII. STATE PARTICIPATION IN RTO OPERATIONS (PP 551 – 555)

State regulatory commissions should continue to play important consumer protection and retail market roles after SMD is in place. It is appropriate to establish RSACs that will have direct contact with ITP Boards.[168] RSACs should be separate from the market participant committees since states will have a different perspective and a unique status. ITPs should pay close attention to RSACs' guidance on issues that are of interest to them.

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168 *See* NOPR at P 552.

The Commission should not, however, share its regulatory responsibilities with states, subject ITPs to state regulation, or compel ITPs to obey RSAC directives. Some language in the NOPR could be read as giving RSACs authority over, among other things, ITPs' "management and budget," which would undermine ITPs' independence. Likewise, States should not oversee MMUs (or ITP market monitoring staffs) because their consumer protection responsibilities could give them an incentive to favor buyers' interests.[169] Empowering States in this way could raise non-delegation issues, might be inconsistent with the Commission's Federal Power Act obligations and could result in a "crazy quilt" of state regulation affecting multi-state ITPs, thus diluting the benefits of uniform market regulation. The RSAC's role should thus be advisory.

XIII. GOVERNANCE (PP 556 - 574)

The NYISO supports the distinction contained in the NOPR between newly formed ITPs or RTOs and those formed as a result of mergers of existing organizations. We believe that the distinction should also extend to ITPs formed out of ISOs with a history of successful governance. The Commission would remain free to apply those portions of its generic rule which it regards as essential.

A. ITP Boards Should Be Fully Independent from Stakeholders

The NYISO agrees with the NOPR that it "is critical that the board be independent" but we believe that the independence of the board is compromised by a board selection process that leaves directors subject to election by market participants.

169 The NYISO does not object to the NOPR's proposal that MMU reports be submitted to RSACs at the same time that they are submitted to the ITP Board and the Commission.

The NOPR prescribes a board selection process that leaves the board ultimately accountable to market participants.[170] The NOPR proposes that all ITP directors, with the exception of some of the initial directors on Boards that result from ISO, RTO, or ITP mergers, would be selected by majority market participant vote. Elected officials are normally presumed to represent and be accountable to their constituents, not to be independent from them. Elected directors, or director candidates, will have an incentive to "grandstand" and seek market participants' favor. This problem would be compounded if the Commission were to require that board meetings be open to market participants.

Even assuming that elected directors would resist market participant pressures, it is possible that their decisions will be affected by them, if only on the margins. If there were never any actual influence, there would still be an appearance of compromised independence. The Commission has consistently held that "the perception that the authority who controls the interstate transmission grid is biased can be enough to prevent proper market forces from working, thus hindering market reliability and efficiency."[171] The Commission should not adopt governance rules that will foster this perception.

The problem of undue influence is exacerbated by the fact that the NOPR would apparently restrict voting to the twelve members[172] of the "nominating committee." This

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170 NOPR at PP 565-68, 571-572, 573.

171 *Mirant Delta, LLC, et al. v. Cal. Indep. Sys. Operator Corp.,* 100 FERC ¶ 61,059 at P 53; *order on reh'g*; 100 FERC ¶ 61,271 (2002) ("*Mirant*"). *See also* Order No. 2000 at 31,061 (finding that an RTO's governance must be independent "in both reality and perception"); Order No. 888 at 31,731 (stating that an "ISO's rules of governance . . . should prevent . . . [the] appearance of control . . . of decision-making by any class of participants").

172 *See* NOPR at P 561 (stating that ITP Boards must be advised by at least six Commission-defined stakeholder classes); P 566 (specifying that the "nominating committee" will be comprised of two members from each stakeholder class).

committee would have disproportionate influence over the composition of the Board, and each member would have similarly disproportionate influence. It is inappropriate to concentrate so much power in so few hands. Moreover, the NYISO's experience has been that controversial policy issues tend to divide market participants into two sides, buyers and sellers. The NOPR, overlooks this and prescribes that all ITPs adopt a voting structure based on stakeholder classes that would give buyers a four class to two advantage in regions like the Northeast where there are no longer vertically integrated utilities.[173] This could result in ITP Boards that are selected by buyers and tend to favor their interests.[174]

The NYISO is also concerned that qualified candidates will be less likely to agree to serve on ITP Boards if they must first submit to a competitive election process. The best candidates will often be people who have achieved high places in life, and they have many opportunities to serve in positions that will not require them to curry favor with market participants. The recent RTO West order acknowledged this when it gave the "Trustee Selection Committee" discretion not to hold Board elections when doing so would "impede the candidate recruitment process."[175] RTO West's director selection model appears to have been the basis for the NOPR's rules. Given that the Commission has already made a change to the RTO West

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173 The "buyer classes" would be: (i) transmission owners (which are predominantly buyers when they have divested their generation); (ii) end-users and retail energy providers; (iii) public interest groups; and (iv) transmission-dependent utilities (which tend to be buyers in the Northeast). The "seller classes" would be: (i) generators and marketers; and (ii) alternative energy providers. If each class has two votes on the nominating committee the end result would be an 8-4 voting advantage for buyers.

174 This problem is especially acute in the current environment, in which many vendors are struggling for survival.

175 *Avista Corp., et al.,* 100 FERC ¶ 61,274 at PP 23, 31 (2002).

model, it should also be open to changing the NOPR to the extent necessary to ensure that all ITPs can attract outstanding directors.

In the event that the Commission does not adopt these recommendations, it should at a minimum provide that directors: (i) will always be elected as a slate, rather than individually, in order to insulate them from inappropriate pressure or retribution; (ii) will be elected by a larger, more representative stakeholder committee or by all stakeholders; and (iii) may only be removed from office for cause, with "cause" being carefully defined. The Commission should also clarify whether the "nominating committee" is actually a "selection committee" that elects directors, as seems to be intended, or whether all stakeholders will vote on the nominees.

B. The Commission Should Not Apply Standardized Rules for ITP Boards That Are Created As a Result of ISO, RTO or ITP Mergers (PP 573 -574)

The NOPR correctly distinguishes between generic rules applicable to brand new organizations and rules applicable to organizations formed as a result of voluntary mergers. As a co-sponsor of the Joint Petition for NERTO, the NYISO appreciates the NOPR's recognition that sitting ISO directors have unique expertise, knowledge and experience that would be needlessly discarded if post-merger ITPs were required to have entirely new Boards. Each merger proposal will, like the Joint Petition, raise numerous complex issues that do not lend themselves to standardized solutions. They will have been taken after extensive stakeholder discussions and reflect a careful balancing of competing interests. They will also have been approved by independent directors that have the same responsibility to make decisions in the best interests of the markets (and consumers) that the NOPR proposes for ITP directors. The Commission has decided to trust directors to make critical market and reliability decisions, after consulting with stakeholders, and should be no less willing to trust their decisions about the governance of post-merger entities. There should be a presumption that post-merger governance proposals that have been approved by independent directors are reasonable and will be accepted.

These considerations are especially applicable to the formation of the NERTO. The NYISO Board of Directors has gone through a thorough and painstaking orientation process. It has guided the ISO through a difficult, but ultimately successful shakedown of complex new markets. It has repeatedly demonstrated its ability to resolve market participant disputes with fairness and impartiality. When new members are added to such a board, common sense dictates that the existing board have the major say in the selection process.

Moreover, for the same reasons set forth above in Section XIV.A., the final SMD rule should ensure that the directors of post-merger ITPs are not subject to the whims of stakeholders. New directors should be chosen by ITP Boards with the advice of stakeholders. Allowing market participants or state regulatory commission to choose, or remove, directors will subject Boards to inappropriate outside influence and compromise their ability to fulfill their responsibilities impartially. Directors must retain their independence from market participants to remain effective.[176] Few, if any, qualified candidates are likely to agree to serve under the governance model proposed in the NOPR.

If the Commission decides not to modify the NOPR's governance proposals for all regions, it should at a minimum waive them for the Northeast and accept the governance aspects of the NERTO proposal. In recent RTO orders, the Commission has signaled that it is willing to

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176 Although the NYISO Board currently does not have unilateral Section 205 filing rights, it is self-perpetuating and stakeholders do not control its membership. Its decision-making process is fully independent of stakeholders even though it is not always free to act without stakeholder support.

allow significant regional variations from SMD standards.[177] A governance variation would be warranted in the Northeast because utilities in both New England and New York have divested substantially all of their generation. As a result, economic differences between market participants are more sharply drawn in the Northeast than in other regions, where vertically-integrated utilities are prevalent. This distinction makes it more difficult for market participants to achieve consensus and strengthens their incentive to use any leverage they have over an ITP Board to advance their own interests. Thus, while it is possible that the NOPR's governance proposals might not have serious negative effects if applied in other regions, they would be more likely to reduce the independence of a Northeastern ITP.

Finally, if the Commission does not modify the NOPR's approach, it should at least clarify the provision that states that an "initial nominating committee" comprised of two directors from each merging ISO and two stakeholder representatives will nominate the initial ITP directors that do not come from the merging ISOs.[178] The Commission should at least make it clear that while the nominating committee will nominate the initial "non-ISO" directors, the existing ISO boards will actually vote to accept them.

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[177] *See, e.g., Cleco Power LLC, et al.*, 101 FERC ¶ 61,008 at P 2 (2002) ("[U]nless the Commission has specifically indicated in this order that that an element of the RTO proposal is inconsistent with the SMD proposal or needs further work in light of the SMD proposal, we do not intend, in the final SMD rule, to revisit prior approvals or acceptances of RTO provisions because of possible inconsistencies with the details of the final rule.").

[178] *See* NOPR at P 574.

C. The Commission Should Not Adopt Prescriptive Governance Rules (PP 561-64, 570)

The NYISO believes that the NOPR proposes excessively detailed and prescriptive governance rules.[179] While it is clearly reasonable for the Commission to establish the basic principles of ITP independence, there is no reason to standardize the number of ITP directors, the length of their terms, their term limits or other miscellaneous details normally included in Board bylaws. Allowing different ITPs to adopt procedures and rules that fit their needs will not create "seams," adversely affect markets or jeopardize ITPs' independence. Forcing them to adopt inflexible "one-size-fits all" rules will only produce needless inefficiency.

Nor is there a good reason to prescribe the number or composition of advisory stakeholder committees. These matters are best left for market participants to resolve themselves.[180] This is especially true if, as seems to be true under the NOPR, the committee structure will influence Board elections by determining which stakeholders will vote. As was noted above, the committee structure proposed in the NOPR would not evenly balance stakeholder interests in the Northeast, and tends to favor buyers. The NOPR committee structure may also under-represent merchant generators, which are relatively more prevalent in the Northeast than in several other regions, and over-represent transmission-dependent utilities, which are relatively uncommon. It seems likely that the NOPR's standardized structure will also

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179 *See* NOPR (Commissioner Breathitt concurring, at 5) ("With respect to governance, I do not agree with the level of prescription that we are imposing on certain governance proposals. I don't think that the Commission should be dictating with such specificity so many rules concerning the explicit makeup of stakeholder committees, who can sit on which committees and exactly how boards should be selected.")

180 In the Petition, ISO-NE and the NYISO suggested there should be at least five principal sectors, generator owners, transmission owners, public power and environmental parties, other suppliers and end-use consumers. They also believed that demand response resources should have a formal voice in the participant structure. The Petition also indicated, however, that market participants should ultimately decide on sector structures themselves.

prove to be a poor fit for other regions. Given that the NOPR would not require ITPs to commence operations until late 2004, there is no need to impose one-size fits all sector structures at this time. The Commission should instead allow each region to develop structures that work for that region.

The NYISO is aware that the Commission proposed the six class structure because it believed that transmission-dependent utilities and proponents of new technologies were inadequately represented in the past.[181] The Commission should reconsider whether the need to be certain that all participants have a voice is so great that it outweighs the inefficiencies of imposing an identical stakeholder committee structure on all regions. We agree with the importance of all interests being represented, but this goal can be met by allowing the region to choose the means of achieving that goal, with appropriate case by case Commission review to assure that it is met.

The final SMD rule should also clarify that state entities that participate in the electricity markets and do not perform a regulatory function should be viewed as market participants and should participate in the stakeholder advisory committees instead of the RSAC. Certain NYISO market participants have expressed concern over the NOPR's ambiguity on this point.

The NOPR also proposes[182] that a company, including all of its affiliates, may have a representative in only one stakeholder sector, in order to "prevent large corporations from dominating sector representation by placing their affiliates and subsidiaries in several sectors." This rule is only necessary to the extent that voting takes place, and affiliates should be able to participate but not vote in additional committees. This change assures that all interests are heard,

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181 *See* NOPR at P 561.

182 *See* NOPR at P 561.

but that large organizations do not exercise undue influence. It has worked well in New York, and should be permitted to continue.

The NYISO supports the *Joint Comments* in its opposition to the NOPR's overly prescriptive director expertise qualifications. While the Commission's desire to ensure that directors have significant relevant experience is understandable, the NOPR sets forth[183] an apparently exclusive list of the types of expertise that at least one member of an ITP Board must possess. This is unwise and unnecessary. The Commission should, instead, revise the NOPR to clarify that it is simply offering guidelines on the general areas of expertise that directors ought to have. An illustrative list should be expanded, at a minimum, to include such areas as economics, management, operation of markets, insurance, human resources, and engineering fields in addition to electrical engineering. Regional flexibility would permit skill sets particularly required for that region. For example, hydroelectric experience might be particularly valuable in the Northwest.

Finally, the NYISO shares the *Joint Comments'* view of the NOPR's proposal to guarantee that directors and their immediate families do not have any ties to market participants. As an enforcement mechanism, the Commission would require directors, their immediate families and senior offices to fill out annual financial disclosure statements subject to audit by the Commission.[184] The Commission does not address the scope of, or the level of detail to be included in, the disclosure statements, or the extent to which such statements would become public documents. The NYISO concurs with the *Joint Comments'* concern that the imposition of

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[183] *See* NOPR at P 563.

[184] *Id.* at P 564.

financial disclosure requirements as stringent as those that apply to senior Federal officials[185] would discourage qualified candidates from serving as directors. The Commission should either trust Boards to develop their own financial disclosure rules or, at a minimum, allow more flexibility than the NOPR contemplates.

D. <u>Other Issues</u>

The NOPR seeks comment, "on whether or under what circumstances a stakeholder class should be able to take an issue directly to the board outside the stakeholder process."[186] The NYISO currently holds special "liaison committee" meetings under which its Board holds regular face to face meetings with small groups of market participant representatives. The NYISO has found liaison committee meetings to be helpful and suggests that the Commission encourage future ITP Boards to use them.

The NOPR also seeks comment, "on whether the [CEO] of the [ITP] should be a non-voting member of the Board."[187] At the same time, the NOPR states that "the Board should be composed of members that are not part of the management of the [ITP],"[188] which seemingly precludes CEOs from serving as directors. This would be a mistake because CEOs will have a level of knowledge and experience, especially concerning day-to-day ITP operations, that will be valuable to the other directors. Nevertheless, the NYISO believes that ITP CEOs should be non-voting. Since a CEO serves at the pleasure of the board, he or she would always have an incentive to vote with the majority or in a manner to please whatever director or directors fix

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185 *See* 5 U.S.C. § 102 (2002) (required content of disclosure reports).

186 NOPR at P 561.

187 NOPR at P 567.

188 NOPR at P 558.

compensation. The NYISO's CEO has been a non-voting director since the NYISO's inception and the system has worked well.[189]

Finally, the Commission should not require ITP Boards to adopt a mandatory "open-meeting" policy.[190] Open meetings would discourage frank debates and encourage pandering to special interests.[191] They would also be cumbersome, if not totally unworkable, and would bring no offsetting benefits given the existence of an advisory stakeholder process and liaison committees.

XIV. SYSTEM SECURITY (PP 575 – 579, 594)[192]

The NYISO commends the Commission for taking the lead in the development of security regulations and supports its use of the NERC security standards as they are developed. The Commission should, however, clarify precisely what role (if any) ITPs are to play in reviewing their members' and customers' compliance with the standards. It should also clarify that the NERC security standards include a physical security, as well as a cyber-security component, at least with respect to the physical security of critical computer and information systems.

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189 In addition to the views expressed herein, the NYISO also supports the position of the *Joint Comments* on these issues.

190 Although the NOPR was silent on this issue, a recent California ISO order specified that "Board meetings will be open to the public (except for matters concerning personnel, security, and litigation), and agenda and briefing papers for any Board meeting must be made available for public review and comment for a specified time prior to an applicable meeting (except in cases of emergency)." *Mirant,* 100 FERC ¶ 61,059 at P 66 (2002).

191 This provision would be especially burdensome if coupled with a board selection process such as the one proposed in the NOPR.

192 In addition to the views expressed herein, the NYISO also supports the position of the *Joint Comments* on these issues.

The NOPR states that transmission-owning utilities must provide ITPs with "assurances" of compliance with the NERC standards, as must customers that wish to take transmission and market services. Providing the assurance will normally involve filing a copy of the Commission's security self-certification form or presenting it to an ITP. Alternatively, customers may work with the ITP to "develop an alternative arrangement for ensuring that the customer has a basic security program in place."[193] The NOPR does not say whether ITPs are required to evaluate the quality of the assurances they receive or take other actions to test system security. In addition, it does not specify whether there will be an adjudicative process to resolve compliance issues, or what ITPs are expected to do when service to non-compliant customers is terminated.

The Commission should eliminate these ambiguities in the final rule. It should carefully consider what obligations to impose on ITPs, since their transmission and market expertise will not necessarily endow them with security expertise. If ITPs are assigned extensive security responsibilities they will probably have to hire specialized staff and may lose their focus on administering efficient wholesale power markets. The NYISO believes that ITPs should not be required to verify the accuracy of market participants' self-certifications. In the event that they are given this responsibility, they should not be subject to liability for failing to detect invalid self-certifications.

XV. IMPLEMENTATION (PP 580 – 594)

A. The Status of Existing ISOs (PP 127, 587)

The NOPR requires all public utilities that own, operate or control interstate transmission facilities to consult with regional stakeholders to develop an ITP implementation plan and file it

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193 NOPR at P 577.

no later than July 31, 2003. The plan must identify the independent entity that will serve as the region's ITP. The NOPR suggests that existing RTOs and ISOs that meet the NOPR requirements may become ITPs, but does not indicate that they should be the first choice. It would allow utilities that have already joined ISOs or RTOs to seek a waiver of the requirement to join a new ITP, but does not specify whether ISOs or RTOs may offer themselves up as a region's ITP candidate.

Some stakeholders may see these ambiguities as an invitation to extract policy concessions from ISOs and RTOs by threatening to oppose their selection as ITPs. The NOPR should not give them this kind of leverage. Replacing a functioning ISO or RTO with an entirely new operator would be wasteful, expensive and inconsistent with the NOPR's goal of keeping the SMD transition costs reasonable.[194] The Commission should establish a rebuttable presumption that existing transmission institutions will become the ITP for their region. Transmission owners would still have a right to choose a different ITP if there were legitimate reasons for the change.

B. <u>SMD Implementation Timetable (P 588)</u>

The NYISO urges the Commission to reconsider the NOPR's September 30, 2004 deadline for full compliance with SMD. Although the Commission has left the door open to possible extensions,[195] it would be wise to set a more realistic goal up front. Even ISOs that already have market designs similar to SMD will find it challenging to meet the deadline, at least with respect to certain SMD components. For example, although the NYISO (or its successor)

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194 *See* NOPR at P 587 ("The Commission wants to ensure that the cost of implementation of [SMD] is reasonable, and intends to closely monitor the expenditures incurred to implement the final rule.")

195 *See, e.g.,* NOPR at P 580.

will be close to full SMD compliance when it implements its RTS/SMD 2.0 software in the first quarter of 2004, it will not be possible to bring the entire Northeast into compliance until 2005 or 2006. PJM and the MISO have also indicated that they will have difficulty launching their single "joint and common" market, which will not include all of the NOPR's proposed features, by the deadline. The NYISO itself was in development for over five years before it launched its current markets, and its creators had the advantage of building on the foundation of a tight power pool. Regions without this history are likely to need as much time, despite the fact that they will be able to learn from the Northeastern ISOs' experiences.

The problem of meeting the NOPR's deadline is exacerbated by the fact that the date of issuance for the final SMD rule appears to be slipping. The Commission has already extended the comment period by a total of four months and there are indications that the final rule will be delayed even further.

Rather than set an arbitrary deadline the Commission should adopt the approach that it took when it conditionally accepted ISO-NE's "SMD 1.0" proposal. There, the Commission accepted ISO-NE's assessment of how long the key implementation tasks would take.[196] The Commission should similarly defer to the expertise of other transmission organizations and allow them to propose deadlines that are realistic for their regions.

If the Commission rejects this recommendation, it should at a minimum extend the September 30, 2004 deadline to correspond to delays in the issuance of the final rule. The Commission appears to have originally expected to complete a final rule by January 2003, and therefore must have assumed that SMD implementation would take approximately eighteen

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[196] *See* 100 FERC ¶ 61,287 at P 72 (concluding that it was reasonable for ISO-NE to take eighteen months to implement nodal pricing for loads.)

months, *i.e*., from January 2003 through September 2004. ITPs should have no less than eighteen months from the date that a final rule is issued to complete the implementation of SMD because it would be unreasonable for them to begin serious software and systems work until the Commission's final requirements are clear. Thus, if a final rule is not promulgated until May 2003, the SMD implementation deadline should be moved back January 2005.

C. Other Implementation Deadlines (PP 580 – 591)

For the same reasons noted above, the Commission should extend the NOPR's other proposed deadlines to reflect any delays in the issuance of a final rule. These include the July 31, 2003 deadline for submitting an interim tariff and implementation plan and the December 1, 2003 deadline for filing SMD tariffs. The other NOPR deadlines do not need to be changed because they are already tied to the issuance date of a final rule, *e.g.,* the requirement that a regional transmission planning process begin six months after the rule is published.

XVI. MISCELLANEOUS TARIFF ISSUES

In addition to its comments on the text of the NOPR, the NYISO also wishes to address the following issues, which arise under the draft SMD tariff.

A. Billing and Payment Issues

Part I, Section 5.1 of the draft tariff requires ITPs to issue invoices "[w]ithin a reasonable time after the first day of each month" and requires Customers to pay all ITP invoices within 20 days of receipt. Based on its own experiences, the NYISO believes that the tariff should establish precise timeframes for issuing and paying bills each month. The tariff should also specify the date on which ITPs must pay suppliers.

Section 5.2 should be revised to expressly state that the Commission's refund interest rate will only apply to unpaid amounts related to billing, not to unpaid amounts that are held by an ITP for financial assurance or working capital purposes.[197]

Section 5.3 gives Customers too much time to correct failures to pay bills without triggering a default. This problem is compounded by the fact that ITPs must continue to serve Customers that dispute their bills, provided that the Customer continues to pay disputed funds into an independent escrow account. ITPs that do not own transmission assets will have very limited financial resources and will not be able to pay amounts owed to suppliers if customers withhold money they owe to the ITP.[198] The draft tariff's provisions are potentially very harmful to ITPs, which would be subject to severe financial disruptions and would be disadvantaged in any bill dispute negotiations, if the escrow term is not changed. A much shorter cure period, such as the two-day period currently used in New York, should be adopted for defaults that involve payments for ITP market services. Customers should be required to continue paying disputed amounts to ITPs. Finally, to avoid undercutting ITPs' authority, and bogging ITPs down in arbitration proceedings, billing disputes should not become subject to the tariff's arbitration provisions until the ITP issues a final bill.

B. <u>Force Majeure and Indemnification</u>

To reflect the unfortunate new reality facing the electric utility industry, the definition of force majeure in Part I, Section 7.1 should be expanded to expressly include terrorism. Section

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197 *See, e.g.*, *Cargill Alliant, L.L.C. v. New York Indep. Sys. Operator, Inc.,* 101 FERC ¶ 61,141 (2002).

198 *See, e.g., N. Y. Indep. Sys. Operator, Inc. v. New York State Electric & Gas Corp.*, 94 FERC ¶ 61,019 (2001).

7.2's indemnification provisions should be modified in a manner consistent with the NYISO's comments in Section X.E. above.

C. **<u>Creditworthiness</u>**

Part I, Section 8 of the draft tariff should include a default provision that specifies the consequences for Customers that fail to maintain their creditworthiness. Alternatively, the Commission should specify that ITPs may address this issue in their individual credit review procedures. Because most ITPs will be highly vulnerable in the event of a Customer default, they must have stronger protections than are included in the draft tariff.

D. **<u>Dispute Resolution</u>**

Part I, Section 10 of the draft tariff should allow parties to a dispute that cannot be resolved informally to pursue some means other than external arbitration to resolve disputes. Some disputes might be addressed through a mediator and some disputes will not be big enough, or sufficiently time sensitive, to warrant formal arbitration.

E. **<u>Confidentiality</u>**

The Commission should revise Part I, Section 12.3 to permit ITPs to share Customers' confidential transmission system information with other ITPs when necessary for reliability purposes without making that information publicly available. It is not clear whether this sort of limited disclosure would be allowed under the current draft tariff.

F. **<u>ITP Responsibilities</u>**

Part II, Section 1.2 of the draft tariff states that an ITP "shall plan, construct, operate and maintain its Transmission System . . . ." It is not clear how this language would be applied to ITPs that do not own transmission assets. The Commission should revise it to avoid creating a presumption that ITPs must own the assets they operate.

XVII. CONCLUSION

WHEREFORE, for the foregoing reasons, the New York Independent System Operator, Inc., respectfully requests that the Commission adopt the recommendations set forth in these comments.

Respectfully submitted,

/s/ Ted J. Murphy
Counsel for
New York Independent System Operator, Inc.

Robert E. Fernandez, General Counsel and Secretary
Mollie Lampi, Assistant General Counsel
New York Independent System Operator, Inc.
3890 Carman Road
Schenectady, NY 12303

Arnold H. Quint
Ted J. Murphy
Hunton & Williams
1900 K Street, N.W.
Suite 1200
Washington, DC 20006

Ira L. Freilicher
Kathy Robb
Hunton & Williams
200 Park Avenue
New York, NY 10166

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cc: Daniel L. Larcamp, Director Office of Markets, Tariffs and Rates, Room 8A-01, Tel. (202) 502-6700
Alice M. Fernandez, Director Office of Markets, Tariffs and Rates -- East Division, Room 71-31, Tel. (202) 502-8284
Robert E. Pease, Acting Director of Division of Enforcement, Office of Market Oversight and Enforcement, Room 52-41, Tel. (202) 502-8131
Michael A. Bardee, Lead Counsel for Markets, Tariffs and Rates, Room 101-09, Tel. (202) 502-8068
Stanley P. Wolf, Office of the General Counsel, Room 101-03, Tel. (202) 502-8891

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each party designated on the official service list compiled by the Secretary in the above referenced dockets, in accordance with the requirements of Rule 2010 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 2010 (2002).

Dated at Washington, DC this 15th day of November, 2002.

/s/ Ted J. Murphy

Ted J. Murphy
Hunton & Williams
1900 K Street, N.W.
Washington, DC 20006-1109
(202) 955-1500