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APPENDIX C

Examples of Flaws in the Current Regulatory Environment

We set forth below specific examples of undue discrimination and impediments to competition that continue to exist in the electric industry. Some of the examples that we provide do not use specific names because they are for the most part based on complaints made through the Commission's Enforcement Hotline, which are handled on a confidential basis. Other examples, which illustrate the potential for discrimination, establish that transmission providers have both the incentive and ability to exercise transmission market power against competitors in the market to supply energy.

<u>Available Transfer Capability and Affiliates</u>

The following is an example derived from informal, non-public inquiries to the Commission[1] regarding a transmission provider favoring itself or its affiliate using Available Transfer Capability postings:

In February, a competing generator recognizes an opportunity to sell power into a vertically integrated transmission provider's system during the summer months (June, July, and August) and, therefore, requests monthly firm service for the desired points for that time period. The transmission provider, which would prefer that its merchant function capture the sales anticipated by the competitor, now must evaluate whether sufficient Available Transfer Capability will be available to honor its competitor's

[1] Because this example is based on non-public inquiries, we have not identified the companies.

request. Although the formula for calculating Available Transfer Capability is required to be public, the transmission provider has the sole responsibility for, and a great deal of discretion in, its calculation, and will be very conservative in its estimates of expected contingencies, outages and the like. In this example, the transmission provider assumes two generating units will be unavailable, reducing Available Transfer Capability below the level where the requested transmission can occur, so it denies the request for summer service. But after the competitor's request is denied, the transmission provider's affiliate can ask in May for weekly firm service over the summer. So, when the affiliate's request is made, it is granted. Discretion on the part of the transmission provider in calculating Available Transfer Capability coupled with the affiliate's knowledge of how the calculations work enable the affiliate to secure the necessary firm service and win the sale opportunity.

<u>Discretionary Use of TLRs</u>

The following is another example derived from informal, non-public inquiry by the Commission regarding how TLRs are used.[2]

The facts: There are three neighboring, interconnected transmission systems, WestCo, CentralCo, and EastCo. (Their relative locations match their names).

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[2]Because this example is based on non-public inquiries, we have not identified the companies.

> CentralCo has 10,000 MW of generation and 8,000 MW of load west of a constrained line that divides its system. The line is limited to 1,500 MW of transfer capability. CentralCo has 1,000 MW of generation and 2,000 MW of load east of the constraint. Its cost of generation on either side of the constraint is comparable, and averages about $25 per MWh.
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> Under its normal dispatch pattern, CentralCo would generate 1,000 MW from its generation in the east to serve the eastern load, and would generate 9,000 MW from its western generation, 8,000 MW to meet its western load and 1,000 to meet the remainder of the 2,000 MW load in the east. This means that 1,000 MW of generation would usually flow across the constrained line for CentralCo to meet its own load, leaving 500 MW of west-to-east ATC on the constrained line.
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> NewGen, a generator located in WestCo's service area, wants to sell 100 MW for one day to a buyer in EastCo's service area. NewGen's cost of generation is $22 per MWh.

To make the sale, NewGen must secure 100 MW of transmission across CentralCo's system (including the constrained line), to make the sale. Therefore, NewGen requests transmission service through CentralCo's system. Under normal operating conditions, CentralCo's constrained line has available 500 MW of Available Transfer Capability, leaving plenty of transfer capability to accommodate the sale. Since its OASIS lists 500 MW of Available Transfer Capability, CentralCo grants the request.

If CentralCo were an RTO, it would have no financial interest in which generator makes any particular sale, and would focus on ensuring optimal and reliable system operation. Thus, it would dispatch the system to ensure that the 100 MW NewGen transaction would flow, since it could do so while still optimizing the dispatch of the CentralCo generators. But CentralCo has a financial incentive to block the NewGen transaction in order to make the sale itself and it has the information to make it happen. CentralCo, as transmission provider, knows the flow patterns on its system and the identity (and affiliation) of all generators flowing power on its system. This means that CentralCo's transmission arm would not need to engage in any prohibited off-OASIS communications to dispatch the system in a way that favors its own affiliate.

CentralCo can block a portion of the competitor's transaction by changing its own dispatch pattern and declaring a TLR across the constrained line. CentralCo would reduce generation on the east side to 500 MW and increase generation from the west by the same amount to meet the eastern load. This would increase its own use of the constrained line to 1,500 MW which, in addition to the 100 MW of scheduled use by NewCo, would exceed the thermal limits of the line. CentralCo, as security coordinator for its own system, has great discretion as to when and for how long to declare a TLR across the constrained line. In this situation, rather than redispatching its own generators to accommodate NewGen's transaction, it could declare a TLR and curtail a portion of the NewGen's transmission transaction.

By curtailing transmission for a portion of the competitor's sale, this TLR allows CentralCo to step in to provide EastCo's needed 100 MW (following NewCo's transmission curtailment), possibly at an inflated price due to the TLR and the buyer's need to immediately secure replacement power.

The Commission is concerned that the use of emergency procedures offers opportunities for discrimination. A high incidence of TLRs reduces certainty in the market because it frustrates the expectations of bulk power sellers and their customers.[3] In turn, it provides a disincentive for market participants to take transmission risks and decreases overall liquidity in the transmission market.[4] The practice of using TLRs to manage congestion contributes to transmission and energy prices that are not just and reasonable and must be remedied.

Lack of Common Set of Rules Governing Transmission

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[3] See Staff Report to the Federal Energy Regulatory Commission on the Bulk Power Markets In The United States (Nov. 1, 2000), available in <http://www.ferc.gov/electric/bulkpower/midwest.pdf>, at 2-32. See Staff Report to the Federal Energy Regulatory Commission on the Bulk Power Markets In The United States (Nov. 1, 2000), available in <http://www.ferc.gov/electric/bulkpower/southeast.pdf>, at 3-38.

[4] See Staff Report to the Federal Energy Regulatory Commission on the Bulk Power Markets In The United States (Nov. 1, 2000), available in <http://www.ferc.gov/electric/bulkpower/midwest.pdf>, at 2-33 (reporting eroded confidence and decreased liquidity in the Midwest market).

1. Balancing Authority

A market participant that operates a control area may derive a market benefit. The primary function of a control area operator is to maintain a balance between the energy coming onto the grid and the energy being taken off. The North American Electric Reliability Council (NERC) refers to this primary function as balancing and the responsible entity as the balancing authority.[5] The balancing authority has generating resources that it may call on for balancing but also may rely on a neighboring balancing authority for balancing energy, which it must pay back. The payback is typically accomplished by returning energy at a later time.

A transmission customer outside the organized spot market of an ISO or RTO is expected to keep its own grid energy inputs and withdrawals in balance. For example, the customer may be a municipal utility that buys 50 megawatts from noon to 1 o'clock to meet a load that is expected to hover around 50 megawatts at that hour. The transmission

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[5] Because most transmission systems were operated by vertically integrated utilities that performed many types of control functions, the term "control area operator" now lacks precision regarding which of these functions is being referred to in a particular context. Recently, NERC adopted new terminology for use in rewriting its reliability standards. It is eliminating the terms "control area" and "control area operator" and replacing these with several other terms that describe more precisely the functions performed. NERC refers to the entity responsible for maintaining system frequency by arranging for generation to balance load as the "balancing authority." It is this function that is the subject of the first example. See The NERC Functional Model: Functions and Relationships for Interconnected Systems Operation and Planning (visited June 11, 2002) <http://www.ferc.gov/Electric/RTO/mrkt-strct-comments/02-19-02/CACTR-Final-Report-Functional-Model.pdf> for more information on the NERC functional model. See also Transcript of Assignment of RTO Characteristics and Functions Technical Conference, Docket No. RM01-12-000, at 12-34 (Feb. 19, 2002).

customer cannot achieve exact balance in part because retail loads are not completely predictable.[6] To the extent the customer does not achieve exact balance, the balancing authority supplies or absorbs energy for balancing, charging the customer for the energy. For an excessive deviation from the scheduled amount of energy delivery, the transmission customer may have to pay a penalty rate under the public utility's tariff, intended to encourage good scheduling behavior so as to maintain reliable system operation.

A balancing authority outside an RTO or ISO is today typically also a market participant that serves its own power customers. In most cases, it is a large vertically integrated public utility that generates and buys power to meet the power needs of its native load. Such a balancing authority may be able to lower the cost of acquiring balancing energy and achieve a competitive advantage over other market participants that do business on its transmission system. It can rely on a neighboring balancing authority to loan it energy without having to pay for the energy. Further, it may avoid a penalty for excessive deviation. It can later return the energy taken in kind to the neighboring authority and may thus face a lower balancing cost than other energy providers. Although this problem may incur infrequently, it results in an undue cost preference for the investor-owned utility and its customers vis-a-vis the costs that other energy providers incur and pass on to their customers.

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[6] A customer can achieve such balance through dynamic scheduling, which effectively takes it out of the control area.

NERC has recognized a related reliability problem associated with excessive unplanned borrowing of energy in a highly competitive market and is in the process of writing new rules to alleviate this problem.[7] Because compliance with NERC's rules is voluntary, one NERC region filed on behalf of the public utilities in its region so that its rule relating to balancing would be mandatory. On May 31, 2000, the Commission approved a tariff filed by the East Central Area Reliability Council, which is the NERC regional reliability council for an area centered around Indiana, Ohio, and western Pennsylvania.[8] The tariff, designed to maintain reliability in an increasingly competitive region, is intended to eliminate any economic incentive that may exist under current reliability rules for a particular balancing authority to borrow large amounts of energy from neighboring authorities when the price of power is high and return it in kind when the price is low.[9] It does not, however, fully eliminate the economic advantage that a balancing authority that is also a market participant may have over other energy suppliers.

The Commission, in the proposed rule leading to Order No. 2000, using the then-current terminology of the control area operator, said that, in an RTO,

> unequal access to balancing options can lead to unequal access in the quality of transmission service, and that this could be a significant

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[7]See, e.g., Board of Trustees Meeting Highlights (visited May 31, 2002) <ftp://www.nerc.com/pub/sys/all_updl/docs/bot/bot0106h.pdf>

[8]See East Central Area Reliability Council, 91 FERC ¶ 61,197 (2000).

[9]See id. at 61,693-94.

> problem for RTOs that serve some customers who operate control areas and other customers who do not.[10]

The Commission concluded in Order No. 2000 that

> control area operators should face the same costs and price signals as other transmission customers and, therefore, also should be required to clear system imbalances through a real-time balancing market. We believe that providing options for clearing imbalances that differ among customers would be unduly discriminatory.[11]

The Commission has not addressed this issue generically, however, for public utility transmission providers that are not in an RTO. There is a need for a tariff that addresses this issue explicitly for all public utility transmission providers.

2. Receipt and Delivery Point Flexibility

The Order No. 888 pro forma tariff provides nondiscriminatory rules governing the designation of receipt points, where power enters the transmission provider's system, and delivery points, where power exits the system. There are different such rules for network integration and point-to-point transmission customers, as required by the Order No. 888 pro forma tariff. Transmission customers say that these tariff provisions allow a vertically integrated public utility with a native load to provide itself with greater flexibility regarding designation of receipt and delivery points through practices that have become known in the industry as "parking" and "hubbing."

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[10] Order No. 2000 at 31,142.

[11] Id.

To illustrate, a point-to-point transmission customer, such as a power marketer, may be required to reserve transmission for a complete transaction, that is, from an actual generator to an actual power-consuming load. If it is announced today, for example, that generation will be available tomorrow from a particular generator, the marketer may be able to buy the power but unable to reserve the transmission if it has not yet identified a buyer and named its location on the grid. That is, it can name a point of receipt but cannot yet name a point of delivery, so it may be denied a reservation for firm transmission service.

A vertically integrated transmission provider with a native load, however, can buy the power from the same generator, naming that generator as the point of receipt and its native load network as the point of delivery, saying it intends to reduce its own generation to meet its native load power needs. The transmitting public utility is given a transmission reservation. Later, the public utility can find a buyer for the power and say it is making a sale from its freed-up generation, designated as the point of receipt, to the buyer's point of delivery – taking a second transmission reservation for the same power. In effect, the public utility will have reserved transmission for a purchase from the generator and a sale to the buyer in a manner that is not available to the marketer. The public utility is said to have "parked" the power at its native load location while it sought a buyer for the power. Parking can also occur if the buyer is known and transmission to the buyer is reserved, allowing the public utility time to search for a seller to match the buyer's power needs. The time delay involved in parking affords flexibility to a vertically integrated transmission provider that is not available to all transmission customers.

"Hubbing" is similar but does not necessarily involve a time delay. Instead, it involves having more than one seller or more than one buyer, or both. Using the method just described for parking, a transmitting public utility with a native load may reserve transmission to buy power from several sellers and to sell power to several buyers. In effect, it may use its combined native load transmission network location as a hub for trading. It may acquire a portfolio of generators from which to obtain power to meet the power needs of a collection of power buyers, without having to match individual buyers and sellers. This hubbing allows the public utility to capture market efficiencies by combining resources to satisfy collective needs, and to gain a competitive advantage over others who cannot establish a hub because they are required by Point-to-Point Transmission Service rules to match a particular generator with a particular load for each transmission reservation.

This example shows another undesirable difference between two transmission services available to both wholesale and unbundled retail customers, Network Integration Transmission Service and Point-to-Point Transmission Service.

Today, the Commission concludes that the inherent differences in flexibility between the two types of tariff services, including the one described above, are resulting in undue preferences and thereby impeding the most efficient trading of power over the interstate transmission grid. Accordingly, the Commission proposes to create a single transmission service and equalize the playing field so that all transmission customers can park, hub or exercise equal creativity and flexibility in structuring transactions and serving customers.

3. Transmission Transfer Capability Set Aside for Reliability

Transmission transfer capability may be set aside by the transmission provider for either of two reliability-related reasons. One relates to the reliability of the transmission system itself and the other relates to generation reliability. As an example of the first, the power loading on a transmission line may be less than the line's capacity so that it can take up the power flows it must absorb if a parallel line should go out of service. The industry refers to this type of unused transmission capacity as a transmission reliability margin, or TRM. While reliability rules forbid a transmission provider from loading a line beyond its reliability limit, these rules are not necessarily mandatory or enforceable. However, there have been few complaints about discriminatory violations of TRM reliability limits.

Most complaints have related to transmission transfer capability that is set aside to provide for adequate generation. A vertically integrated public utility may have decided in the past that, to achieve adequate generation resources (including reserves), it was more economical to build stronger transmission interconnections with neighbors that could share their extra generation when needed than to build extra generation in its own service area. When Order No. 888 was under consideration, such utilities argued that some transmission transfer capability should be set aside for this generation reliability function.[12] They asserted that, if others were allowed to purchase firm rights to this transmission capability, it would not be available to the public utility when needed for the generation reliability purpose for which it was built.[13] The term used for this type of transmission set aside is capacity benefit margin (CBM). Order No. 888 permitted utilities to have CBM if they fully explained and justified the amount set aside.[14] The CBM set-aside practice is not used universally; some utilities do not claim a capacity benefit margin. Moreover, where it is used, there is regional variation in its implementation.

Since Order No. 888 issued, at least two issues related to CBM have been controversial. One is whether all network transmission customers, including for example municipal utilities within the transmission owner's service territory, have an equal opportunity to set aside transmission for this purpose. The second is whether those who set aside transmission for CBM are reserving it and paying for it under the terms of the pro forma tariff.

The second issue is best explained with an example. Suppose a transmission-owning public utility sets aside 100 MW of transfer capability at its interface with a neighboring utility to help ensure adequate generation for the public utility's native load customers. Suppose further that the public utility's native load is 600 MW, and the

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[12] See Order No. 888 at 31,693-94.

[13] See id.

[14] See id. at 31,694.

collective amount of point-to-point transmission customer imports is 200 MW and the line's total capacity is 900 MW. Under the usual method of allocating transmission costs to customers, the point-to-point customer would pay for and receive 200 MW of transmission service and the public utility would pay for 600 MW of transmission system cost but receive 600 MW of transmission service and 100 MW of reserved capacity. In some cases, the transmission provider's merchant affiliate has used the CBM set-aside on a non-firm basis to make sales without paying for the transmission capacity used.

In 1998 the Commission received complaints alleging that some transmission-owning utilities were inappropriately reducing Available Transfer Capability to reflect transmission reliability requirements and capacity benefit margins.[15] The Commission observed in WPPI that the determination of CBM was made differently in the Available Transfer Capability calculations of various utilities and was not explained in one tariff.[16] The Commission stated that it was "concerned that the exercise of this discretionary adjustment can turn on considerations (such as the reduction of power supply costs and limiting the generation supply options of competitors) that involve the transmission provider's merchant arm rather than its transmission function."[17]

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[15]See Wisconsin Public Power Inc. SYSTEM v. Wisconsin Public Service Corporation, et al., 83 FERC ¶ 61,198 (1998) [hereinafter WPPI].

[16]See id. at 61,857-58.

[17]Id. at 61,858.

In 1999, the Commission initiated a generic inquiry into policies for transmission reliability set-asides. In particular, the Commission convened a conference in May 1999 in which it examined the practices of use, and the alleged abuses, of CBM.[18] Transmitting utilities had been accused of using CBM designations to withhold transmission transfer capability from the wholesale electric transmission market. The Commission also requested comments on the subject. One commenter stated:

> Even NERC acknowledges that there is a wide disparity in the magnitudes of TRM [transmission reliability margin] and CBM applied by transmission providers across an interconnection, especially in the quantification of CBM. The reason for this disparity is the absence of an enforceable industry standard–or more appropriately, a Commission rule–for the definition of CBM.[[19]]

In July 1999, the Commission issued an order clarifying the method for computing ATC, including provisions dealing with CBM.[20] There, the Commission stated that: "[t]he measures that we are requiring transmission providers to take at this time consist of short-term solutions, which, for now, take no position on the transmission provider's

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[18]See Capacity Benefit Margin in Computing Available Transmission Capacity, 64 Fed. Reg. 16730-31 (March 31, 1999), 86 FERC ¶ 61,313 (1999), (hereinafter CBM Notice).

[19]The Electricity Consumers Resource Council and the American Iron and Steel Institute (Industrial Consumers), Docket No. EL99-46-000, written comments at 3 (footnote omitted).

[20]Capacity Benefit Margin in Computing Available Transmission Capacity, 88 FERC ¶ 61,099 (1999).

ability to set aside CBM for generation reliability requirements."[21] The Commission acknowledged that NERC had already started a process to establish a standardized methodology for deriving CBM, and directed public utility transmission providers, working through NERC, to complete this process by the end of 1999.[22]

NERC called on each region to develop and document its own methodologies and guidelines for determining TRM and CBM.[23] It reported that its ATC Working Group was continuing to develop CBM and TRM, and that the draft standards would require each region to develop a region-wide CBM methodology.[24] It also noted that many methods for calculating CBM were used by transmission providers within each region.[25] Although a single North American standard CBM method was called for by transmission customers, NERC reported that it was not able, at that time, to develop such a standard

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[21]Id. at 61,237. The order, among other things, also directed each transmission provider to post specific CBM information and practices on its OASIS site within 30 days of the order, and to reevaluate generation reliability needs periodically so as to make known the availability of CBM capacity to others. See id.

[22]See id. at 61,238.

[23]See Response of the North American Electric Reliability Council to the CBM Order, Docket No. EL99-46-000 (Aug. 12, 1999), at 3.

[24]See id. at 3-4.

[25]See id. at 5.

for CBM.[26] NERC noted that the consideration of a standard CBM method would follow the completion of regional methods,[27] a process that is still ongoing.

The lack of standards for TRM and CBM impedes the development of basic information required by Order Nos. 888 and 889 as a basis for eliminating undue discrimination in the provision of interstate transmission services. Further impeding competition is continued uncertainty about whether and how to account for CBM in determining ATC and how CBM costs should be allocated. The industry needs Commission guidance to achieve standardization in these areas.[28]

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[26]See id.

[27]See Letter from Virginia C. Sulzberger, North American Electric Reliability Council, to David P. Boergers, FERC, Docket No. EL99-46-000 (Dec. 23, 1999), at 2. There have been no further Commission proceedings on a generic basis addressing CBM. Parties did raise the CBM issue in the proceedings leading to Order No. 2000, but the Commission determined that "[t]hese issues are too detailed for this proceeding and we will not address them at this time." Order No. 2000 at 31,146. Development of methods for calculating ATC and CBM at NERC are continuing.

[28]Addressing the topic of ATC coordination, which includes the "[p]roper quantification of transmission reliability margin (TRM)" the NERC ATC Coordination Task Force concluded that:

> the existing definition of ATC coordination does not meet the needs of all members of the marketplace (all market participants) because there are too many diverse opinions that will not allow for consensus. . . . It is impossible to meet the existing definition of coordination due to differing market objectives, and regional business practices and transmission provider tariffs, and corporate objectives. Until these issues are resolved, coordination will not occur.

Available Transfer Capability Coordination Task Force, ATC Coordination and Related

(continued...)

4. Transmission Curtailment Preference for Bundled Retail Load

The Commission continues to receive complaints that transmission service to deliver power to bundled retail customers continues to be superior to transmission services for wholesale and unbundled retail transmission customers. In Northern States Power Company (NSP), the United States Court of Appeals for the Eighth Circuit held that the Commission had exceeded its authority when it rejected proposed transmission curtailment provisions, contained in a public utility's wholesale open access transmission tariff, that favored the utility's retail customers over its wholesale customers.[29] On remand, the Commission permitted NSP to amend its open access transmission tariff to reflect its proposed transmission curtailment procedures to be effective in the "rare circumstances" where generation redispatch is inadequate or unavailable to fully relieve the transmission constraint.[30] However, the Commission also told NSP that if it amends its tariff to reflect its proposed transmission curtailment procedures, "NSP must revise its rates for firm point-to-point transmission service . . . to recognize the inferior quality of

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[28](...continued)
Issues at 8-9 (July 12, 2000), available in
<ftp://www.nerc.com/pub/sys/all_upoll/pc/minutes/ac - 0007m.pdf>.

[29]Northern States Power Company, et al. v. Federal Energy Regulatory Commission, 176 F.3d 1090, 1096 (8th Cir. 1999), cert. denied sub nom. Enron Power Marketing, Inc. v. Northern States Power Company, 528 U.S. 1182 (2000).

[30]See Northern States Power Company (Minnesota) and Northern States Power Company (Wisconsin), 89 FERC ¶ 61,178 at 61,552-53 (1999). Subsequently, the Commission has applied NSP narrowly and indicated that it continues to believe that it has the authority to treat such customers comparably. See North American Electric Reliability Council, et al., 96 FERC ¶ 61,079 at 61,345 (2001).

that service compared to the service provided by NSP to its native load and network customers . . . ."[31]

Although NSP later withdrew its objection to equal transmission curtailment treatment for all transmission customers, the case points out a difficulty the Commission has in ensuring transmission access that is not unduly discriminatory for all transmission customers – retail and wholesale – unless all transmission customers take service under the same tariff.

Seams Problems

Even apparently minor differences in rules can create seams problems. The three Northeastern ISOs, which have substantially similar market designs and transmission congestion management systems, have struggled to coordinate their rules to lower trading barriers, but have achieved only limited success after several years. If each RTO in the Nation were to implement different rules, processes, and market mechanisms, these differences combined could produce and exacerbate significant barriers to transmission and electric power sales in interstate commerce.[32]

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[31]89 FERC at 61,553.

[32]For perspectives on this topic and its possible economic consequences, see Mirant Corporation, Northeast Power Markets: The Argument for a Unified Grid, 139 Public Utilities Fortnightly, at 36-45, Sept. 1, 2001.See also Hartshorn, Andrew P. and Harvey, Scott M., Assessing the Short-Run Benefits from a Combined Northeast Market, LECG, LLC, October 23, 2001.

As an example of a specific seams problem, incompatible ramping rules have made power sales among the ISO systems in the Northeast unnecessarily difficult and prevented some trades. Among the operating protocols of a transmission provider are rules for increasing and decreasing the power output of a generator (called "ramping") connected to the transmission system. To implement a transaction between two systems, generation in the supplying system must be increased, or "ramped" up, and generation in the receiving system must be decreased, or "ramped" down. The ramping up and ramping down in the two systems should begin at the same time, last for the same length of time, and end at the same time. But different systems can have different rules about the timing and rate of ramping. For example, PJM allows ramping to occur every fifteen minutes; it can occur, for example, at 1:00 p.m., 1:15 p.m., 1:30 p.m, 1:45 p.m., 2:00 p.m., and so forth. New York and New England require ramping to occur on the hour, at 1:00 p.m or 2:00 p.m. but not within an hour. Thus, PJM's ramping rules permit a sale from PJM to New York to begin on the half hour by ramping up generation in PJM, but New York's ramping rules do not allow a buyer in New York to receive the power because it cannot ramp down generation on the half hour. Also, systems may place different limits on the amount of ramping that may occur on the interface with a neighboring system. Then, one system may allow an amount to be exported that the neighbor will not allow to be imported.[33] These differences must be reconciled to maximize opportunities for constructive trade at minimal transaction costs and obstacles.

Several efforts are underway at the Commission or within the industry to address seams problems and the development of standards. The Commission issued a Notice of Proposed Rulemaking to standardize rules for interconnecting generators to the grid.[34] The Commission also issued an Advanced Notice of Proposed Rulemaking to extend the standardization requirements of Order No. 889 to include electronic scheduling, among other matters.[35] In response to the latter, the industry formed the Electronic Scheduling Collaborative (ESC) to develop recommendations for the proposed rule but reported that the diversity of business, operating and other practices around the country made it very difficult to develop standards and protocols for electronic scheduling that would apply to all public utility systems. In its October 5, 2001 report to the Commission, the Electronic Scheduling Collaborative identified ten key policy issues that would give significant

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[33] An extensive list of seams issues, ISO rule differences, and a discussion of efforts to reduce seams problems among the Northeast systems is available at the ISO Memorandum of Understanding web site. See Seams Issues – High Priority Items <http://www.isomou.com/working_groups/business_practices/documents/general/bpwg_matrix.pdf >. At the June 12, 2002 Commission meeting, New York ISO presented a list of 40 seams issues in the Northeast and a time line for resolving these issues. See Transcipts of Commission Meetings, June 12, 2002, available in <http:www.ferc.gov/calendar/commissionmeetings/transcripts.htm>.

[34] See Standardization of Generator Interconnection Agreements and Procedures, 62 Fed. Reg. 22,249 (May 2, 2002), FERC Stats. & Regs. ¶ 32,560 (2002).

[35] Open Access Same-Time Information System (Phase II), Docket No. RM00-10-000, Advance Notice of Proposed Rulemaking, 92 FERC ¶ 61,047 (July 14, 2000).

impetus to standards development. All of these issues are addressed in this proposed rule. NERC is working to achieve more uniform and enforceable reliability rules, and the North American Energy Industry Standards Board was formed in the autumn of 2001 in part to develop standards for electric wholesale business practices and communications protocols. Regional groups have formed to address seams issues, including the Seams Steering Group for the Western Interconnection and a Memorandum of Understanding among the three Northeast ISOs and the Ontario Independent Market Operator to address seams issues. In the Midwest, over the last several years various groups have met to deal with seams issues between two or more proposed RTOs for the central United States. The Tennessee Valley Authority (TVA) has also negotiated memoranda of understanding with Midwest Independent System Operator, Entergy and Southern Companies to pursue development of a coordination agreement to address seams issues in the Southeast. In its RTO orders, the Commission has been concerned about seams between neighboring RTOs with different rules, and also about seams between entities that are part of one large RTO.[36]

Many panelists at the Commission's seams conference urged us to develop standards for RTOs before they begin operating – indeed before they invest heavily in

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[36] See Alliance Companies, et al., 97 FERC ¶ 61,327 at 62,530 (2001).

software development for a unique set of regional transmission rules and market designs.[37] This urging played a significant role in the genesis of this rulemaking.

Another seams problem can arise from different market price mitigation rules in neighboring regions. When western electric power prices were high in 2001, for a short time the Commission applied price mitigation to certain generators in California for spot market sales of power within California.[38] But these mitigation measures did not apply to sales from these generators to buyers outside California. As a result, some California generators sold power to parties outside California, that sold the power back into the state without facing the same price mitigation rule, a practice that was dubbed "megawatt laundering." The Commission shortly thereafter applied uniform mitigation measures throughout the United States portion of the Western interconnection to remedy this problem. Uniformity of rules eliminated the seams problem in that circumstance.[39]

Market Design Flaws

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[37]Conference on RTO Interregional Coordination, Docket No. PL01-5-000, June 19, 2001.

[38]See San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services into Markets Operated by the California Independent System Operator and the California Power Exchange, et al., 95 FERC ¶ 61,115 (2001). The Commission's order on price mitigation provided in part that certain California generators that had not already sold their power were required to bid into the ISO's real-time market at a constrained bid price.

[39]See New York Independent System Operator, Inc., et al., 92 FERC ¶ 61,073 (2000); NSTAR Services Company v. New England Power Pool, et al., 92 FERC ¶ 61,065 (2000); and PJM Interconnection, L.L.C., 96 FERC ¶ 61,233 (2001) (orders accepting a uniform $1000 bid cap).

The ISO markets have experienced numerous design flaws. A few of the more fundamental flaws are detailed below:

1. Transmission Congestion Pricing by Zones Rather than Nodes

On all single utility transmission systems, the cost of congestion is allocated to all users of the grid on a load ratio share basis. ISOs have tried various ways to allocate these costs to the customer or customers whose transactions caused the congestion. Several ISO markets attempted to price transmission congestion based on the average cost of congestion for transfers of power between defined zones on the system, rather than pricing the transmission congestion on a point-to-point basis. The zonal method tries to allocate congestion costs without too much pricing complexity. The theory of the method is that zones can be established within which little transmission congestion will occur (if any congestion does occur within the zone, all customers receiving power within the zone must share the cost of congestion). Variants of zonal pricing were tried in California, PJM, Texas (ERCOT) and New England.[40] In all cases the methods contained a similar flaw: using the zonal price signal did not induce short-term efficiency in the region, and it spread the congestion costs too broadly to clearly identify the transactions causing the congestion or the location of the structural fixes necessary to resolve it. It has also been

[40] See New England Power Pool, 88 FERC ¶ 61,147 (1999); PJM Interconnection, LLC, 81 FERC ¶ 61,257 (1997), order on reh'g, 92 FERC ¶ 61,282 (2000); Order Proposing Remedies for California Wholesale Electric Markets, 93 FERC ¶ 61,121 (2000).

difficult to determine in advance the appropriate zones, as flows have changed after restructuring.[41]

2. Overly Restrictive Ancillary Service Market Designs

Although the specific designs were different, both the California ISO and ISO New England initially attempted to require sellers to separately bid into each of several ancillary services markets. The hope with this design was to establish vibrant markets for each of the various ancillary services. However, the market design did not allow the substitution of a higher quality product (operating reserve - spinning) for a lower quality product (operating reserve - supplemental), even if the higher quality product was available at a lower price. This resulted in thin markets for certain ancillary services because sellers had no incentive to offer in one market if another market paid more. The perverse result was that lesser quality product markets (such as operating reserve - supplemental) cleared at higher prices than higher quality products (operating reserve - spinning). Sellers had to guess, based on limited information, which service would be the most highly valued. The market design failed to recognize that certain ancillary services were substitutes, e.g., spinning reserves can "provide" supplemental reserves because operating reserves - spinning are more responsive to the ISO's dispatch signal. This design flaw created artificial barriers to entry for certain products, increasing market

[41] This zonal cost allocation for congestion management is different from and should not be confused with proposals to aggregate energy prices at several points into hubs.

power and inefficiency, causing customers to pay prices higher than necessary for ancillary services.[42]

3. The Absence of a Day-Ahead Market

Certain ISO markets, including PJM and ISO New England, began operations with only real-time energy markets. All prices for power sold through the balancing market and ancillary service markets were cleared based on schedules and actual purchases in real time. In all cases, ISOs with only a real-time market concluded that a day-ahead market settlement system was also needed so that transmission customers could better protect against congestion costs, and so buyers and sellers of energy too could better protect against energy price uncertainty.[43] A day-ahead market enhances reliability because it allows the system operator to assess the next day's likely load and available resources. The California ISO has had difficulty operating the system reliably since the California PX ceased operations. A financially binding day-ahead market serves a critical reliability function by facilitating planning, unit scheduling, and load balancing.

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[42] See AES Redondo Beach, L.L.C., et al., 84 FERC ¶ 61,046 (1998); New England Power Pool, 85 FERC ¶ 61,379 (1998).

[43] See PJM Interconnection, LLC, 91 FERC ¶ 61,148 (2000); New England Power Pool, et al., 96 FERC ¶ 61,317 (2001).

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APPENDIX D

Conversion of the Order No. 888-A Pro Forma Tariff to the Revised Standard Market Design Pro Forma Tariff

The following outlines the Order No. 888-A pro forma tariff and indicates where the various sections appear in the SMD Tariff. Where there are modifications or additions, they are identified and described. In addition, throughout the SMD Tariff, we have revised our terminology to match the new NERC terminology.

application for service. Also modified to clarify that any Commission order issued pursuant to section 211 of the FPA would specify that service under this section is provided subject to the customer's payment of all costs deemed eligible for recovery]

<u>Additions to Part I of the Tariff</u>

[replaces definition of Eligible Customer so that "Customer" could apply to transmission and market services.]

[ensures that Transmission Provider and market monitoring unit have access to operational and bid data; additional changes to ensure Commission access to data for investigations]

II. <u>POINT-TO-POINT TRANSMISSION SERVICE</u>

[PTP service replaced by Network Access Service. Section replaced entirely (except as noted) by Network Access Service–many provisions here that are comparable to Network Integration Transmission Service retained]

Preamble

13 Nature of Firm Point-To-Point Transmission Service

[modified to be as short as one hour of service]

[first-come, first served priority system replaced with LMP, "who values it the most" system of rationing capacity]

[load ratio share allocation of redispatch costs is replaced by LMP system]

[narrows focus of section to address only constraints not first resolved by the LMP system; gives priority to customers with adequate resources who are also using Congestion Revenue Rights (question in preamble on whether we should grant this priority)]

[revised to no longer refer to sharing of curtailments between Transmission Provider and other customers – all load-serving entities will now be customers]

[provision in tariff, not Network Operating Agreement; done on a non-discriminatory basis]

[Transmission Provider can propose penalties for failure to follow a curtailment order]

[revised to only apply the load ratio share Access Charge to deliveries to load located on the Transmission Provider's system; through and out service customers would not pay the Access Charge unless they wanted to receive a direct allocation of Congestion Revenue Rights]

[to be filed by Transmission Provider; must be done by an independent entity]

ATTACHMENT D

Methodology for Completing a System Impact Study . . . . Attachment B

[to be filed by Transmission Provider]

ATTACHMENT E

Index Of Point-To-Point Transmission Service Customers . . . . Attachment D

[name change for Network Access Service]

ATTACHMENT F

Service Agreement For Network Integration Transmission Service . . . deleted

[one for all Network Access Service Customers – Part VI]

ATTACHMENT G

Network Operating Agreement . . . . Attachment C

[to be filed by Transmission Provider]

ATTACHMENT H

Annual Transmission Revenue Requirement For Network Integration Transmission Service . . . . Part VIII

[all rates addressed in Part VIII]

ATTACHMENT I

Index Of Network Integration Transmission Service Customers . . . . . deleted

[one for all Network Access Service Customers – Attachment D]

<u>New Sections of the Pro Forma Tariff</u>:

Part II.D. **Congestion Revenue Rights**

Part III. **Day-Ahead and Real-Time Market Services**

Part IV. **Market Monitoring**

Part V. **Generation Interconnection Procedures**

[will be the outcome of the Standardization of Generator Interconnection Agreements and Procedures, Notice of Proposed Rulemaking, 99 FERC ¶ 61,086 (2002)]

Part VI. **Transmission Planning and Expansion**

Part VIII. **Appendices** (Details for calculation of rates and market clearing prices)

APPENDIX E

Standard Market Design and Trading Strategies Encountered in the Independent System Operators

Currently, five ISOs operate organized markets for energy and ancillary services, California ISO, PJM, New York ISO, ISO-New England and ERCOT. This appendix discusses how Standard Market Design would handle various trading strategies that were allegedly used for market manipulation in these ISOs, including those described by Enron Corporation in two memoranda as being used in the California wholesale markets. Standard Market Design incorporates lessons we have learned from experience in these organized markets. In many cases the proposed market rules have been designed to avoid the market design flaws that were the basis for these trading strategies. For others, Standard Market Design relies on strong market monitoring by the Independent Transmission Provider's Market Monitoring Unit and the Commission Office of Market Oversight and Investigation to ensure compliance with the market rules and to detect new market manipulation strategies.

Enron Strategies and Standard Market Design

In memoranda dated December 6, 2000 and December 8, 2000, attorneys for Enron detailed various trading strategies that were being used in California wholesale markets. The strategies discussed in the Enron memoranda were mainly tailored to take advantage of flaws in the California market design, particularly its congestion management system. Standard Market Design uses a different congestion management system that would make most of these strategies infeasible.

Most of the strategies described in the Enron memoranda depended on the development of a day-ahead schedule for power sales that was developed without determining whether that day-ahead schedule was physically feasible. In real time, the California ISO made payments to entities to relieve congestion. This created an incentive for an entity to create congestion in the day-ahead schedule at no cost so that the same entity would be paid to relieve that congestion in real time.

Standard Market Design uses a nodal congestion management system, Locational Marginal Pricing (LMP) together with a physically feasible and financially binding day-ahead schedule. The use of a nodal congestion management system ensures that all transmission constraints are considered in developing day-ahead schedules and any congestion is reflected in the prices for energy and transmission services.[44] Thus, there is no need to make separate payments in real time to relieve congestion in the day-ahead schedule, as there was in California. The day-ahead schedules under Standard Market Design would also be financially binding so that a marketer that changed its schedule in real time would still be financially liable for its day-ahead schedule. This also reduces the

[44]California used a zonal congestion management system that was designed to manage congestion between zones, but not within a zone. A nodal congestion management system is designed to manage congestion between any locations or nodes within the transmission system. In California, the day-ahead schedule for energy sales was developed by the PX and there was no requirement that this schedule be physically feasible.

opportunities and incentives for market manipulation strategies that rely on differences between day-ahead and real-time prices.

A few of the strategies in the Enron memoranda appear to depend on the marketer providing false information to the ISO. Thus, these strategies rely on evading or violating the market rules rather than on market design flaws. Standard Market Design addresses these types of strategies by requiring an active market monitoring program that will detect violations of market rules and take appropriate action against entities that violate the market rules.

The specific strategies in the Enron memoranda are discussed below.

A. The Big Picture

1. "Inc-ing Load" (Fat Boy) - artificially increasing load on schedules submitted to the Cal PX; dispatching the generation as scheduled, which was in excess of actual load; being paid by the California ISO for the excess generation at the market clearing price.

This strategy appears to be designed to evade the requirement for balanced day-ahead schedules by the California ISO. Standard Market Design does not require load or generation to submit balanced day-ahead schedules. Therefore, such a strategy is not necessary to offer excess generation to the market. The market rules provide sellers with varying methods to do this. However, there are scheduling requirements and entities that do not follow them may be subject to penalties.

2. Relieving Congestion – creating congestion in the PX market (i.e., the energy scheduled for delivery exceeds the capacity of the transmission path) and "relieving" such congestion in the real-time market. Accomplished by reducing schedules or scheduling transmission in the opposite direction, for which congestion payment is made by the ISO.

This strategy appears designed to exploit a flaw in the California market design that is not present in Standard Market Design. The day-ahead schedule for energy developed by the PX market did not take into account transmission constraints. As such, the schedule that was developed was often not physically feasible. Second, entities were then paid to relieve the congestion in real-time that resulted from the infeasible day-ahead schedule. In contrast, Standard Market Design uses a security constrained day-ahead schedule for energy. This means the day-ahead schedule accounts for all transmission system constraints needed for reliable system operations. Thus, the day-ahead schedules in the Standard Market Design will not have the type of manufactured congestion discussed in the Enron memoranda. Standard Market Design also uses a more efficient congestion management system, LMP, than that used by the California ISO. Under LMP, the entities that cause congestion are charged for that congestion. Thus, there would be no need for separate payments by the ISO to relieve congestion as occurred in California.

B. Representative Trading Strategies

1. Exports of California power – buying energy for export and then importing that energy to evade the price caps in California.

The strategy was designed to take advantage of the fact that there was a price cap in effect in only part of the market. This problem was eliminated in California when West-wide mitigation measures were imposed. Standard Market Design will apply consistent market mitigation measures across all regions. Thus, the incentive for this type of strategy is significantly reduced. Also, Standard Market Design includes a resource adequacy requirement for load serving entities that avoids or minimizes the energy shortage conditions that made this strategy possible.

2. Non-firm Export – scheduling non-firm energy from a point in California to a control area outside of California and then cutting the non-firm energy after it receives payment for relieving congestion.

This strategy appears to exploit a loophole in the California congestion management system that allowed an entity to get a payment for shipping power that wasn't actually shipped. In contrast, under Standard Market Design the day-ahead schedule would be financially binding so a marketer could not cancel the arrangement without a financial penalty. Also, Standard Market Design uses LMP to manage congestion rather than separate payments to relieve congestion.

3. Death Star – scheduling energy in the opposite direction of congestion (counterflow) without putting energy onto or taking it off of the grid, yet still receiving congestion payments.

This strategy appears designed to exploit a flaw in the way that congestion charges were paid in California. Under LMP, the entity would only be paid in real time for power that actually flowed. Congestion charges would be computed as the difference between two locational energy prices under a LMP system rather than a separate charge as in California. This particular strategy also appears to depend on different congestion management systems being in effect in contiguous areas. That is, the California ISO's congestion charges did not reflect the availability of additional transmission capacity along a parallel path in an adjacent system. As long as that happens there likely are some opportunities for market manipulation. The long-term fix for this type of problem is a standard market design that applies to all areas within the market. Also, large regional organizations that cover natural markets will fix this problem. In Order No. 2000, the Commission encouraged the formation of these types of regional organizations.

4. Load Shift – submitting artificial schedules in order to receive inter-zonal congestion payments. Shifting load to receive congestion payments.

The strategy relies on the flaws in the congestion management system in California. The zonal congestion system used in California provides more opportunities to game congestion than the nodal congestion system under LMP. Because of the separation of the day-ahead market (formerly administered by the PX) and the real-time balancing market (administered by the ISO), there are numerous ways that market participants can create artificial congestion in the day-ahead market and then be paid to relieve the congestion in real time. Under LMP, the entity that caused the congestion would pay for the congestion.

5. "Get Shorty" – paper trading of ancillary services. Enron has to submit false information to the CA ISO on the location of the plants to sell the ancillary services.

Standard Market Design proposes a day-ahead and real-time market for ancillary services. Financial bids for ancillary services are not permitted. Bidders would be required to identify specific units that would be used to provide the ancillary services. Market monitoring would be used to ensure that ancillary service bids are backed by real resources.

This strategy is also based on virtual bidding, something that is allowed under Standard Market Design for energy markets. Virtual bidding should cause the prices in the day-ahead and real-time markets to converge. This by itself does not harm customers. It means that a customer that buys power in real time will pay approximately the same as a customer that buys power day ahead. However, under Standard Market Design, bidders would be required to specifically identify energy bids that are not backed by physical resources. This is important for reliability purposes, to ensure that the transmission provider can ensure that sufficient physical resources are committed to meet the projected load. In contrast, Enron apparently indicated the ancillary bids were backed by physical resources when they were not. This could have affected reliability if Enron was actually called on to supply the ancillary services.

6. Wheel Out – scheduling a transmission flow while knowing that an intertie is completely constrained or that a line is out of service. Even though no energy is delivered, the trader will be paid a congestion charge for cutting the transaction.

This strategy appears designed to exploit two flaws in the California system that do not exist in Standard Market Design. First, because Standard Market Design uses security-constrained unit commitment and dispatch procedures in operating their energy markets, market participants could not schedule transactions day-ahead or real-time that are physically impossible. Second, the congestion management system under Standard Market Design is fully integrated with the energy markets and therefore would not provide separate payments for relieving congestion as in California. Under LMP, if more entities were trying to schedule an export than the physical capacity of the line, this excess would be reflected in the market clearing prices for the energy exports, which in turn would be used to compute appropriate congestion charges. Thus, there would be nothing to gain in using this strategy.

7. Ricochet – Buying energy from the Cal PX and exporting it to another entity which charges a small fee. The energy is resold in the real-time market.

The main purpose of this strategy is to evade California's price caps which apply to in-state generation, but not to external generation purchased "out of market." Under Standard Market Design there would be consistent market mitigation measures across the country. Therefore, there would not be the opportunity to take advantage of the differences in market rules. In California, the "Ricochet" strategy ended when consistent West-wide mitigation rules went into effect.

8. Selling non-firm as firm – selling or reselling what is actually non-firm energy to the Cal PX but claiming that it is firm energy.

The reason for this strategy is that Enron would get paid for ancillary services if the energy was labeled as firm, but would not get paid for ancillary services if it was labeled as non-firm. Under Standard Market Design all transmission service would be under Network Access Service so there would be no difference in the ancillary service requirements. Thus, there would be no reason for this strategy.

9. Scheduling energy to collect congestion charge – scheduling a counterflow even though a company does not have any available generation. The entity is charged the real-time price for energy that it is short but receives a congestion payment for the scheduled counterflow. This activity is profitable whenever the congestion payment is greater than the charge associated with the energy that was not delivered.

This strategy exploited a loophole in the CA ISO congestion management system that does not exist under the LMP system used in Standard Market Design. As the memorandum notes, CA ISO paid congestion charges whether any power flowed or not. Under Standard Market Design if an entity sold energy in the day-ahead market it would either have to provide the energy in real time or buy back its position (it would be charged the real-time price for the energy). Also, the strategy may be related to the fact that the day-ahead schedule for energy developed by the Cal PX did not account for transmission constraints. CA ISO then paid congestion charges to entities to relieve the congestion they had created through their scheduling. The security constrained day-ahead schedules required in Standard Market Design takes into account transmission constraints. So, there is not the same opportunity for this type of market manipulation.

Market Manipulation in the Eastern ISO Markets: Implications for Standard Market Design

Because several components of Standard Market Design are based on market designs in effect in the Eastern ISOs markets – PJM, New York and New England – it is important to turn to these markets to verify that the Standard Market Design rules protect against market manipulation. In this regard, the following points are important. First, the Eastern ISO markets have recognized almost from the start of market operations that no market design can protect against market power due to structural conditions, such as the high concentration of firms in a region or load pocket and/or the lack of price-sensitive demand. For this reason, the Standard Market Design includes market power mitigation rules.

Second, there have been several years of learning in the Eastern ISO markets on market design. Small details of market design can turn out to have major effects on market performance. We have used this experience in developing the market rules for Standard Market Design.

Like the California markets, the Eastern ISO markets have been alleged to be subject periodically to physical and economic withholding of capacity by firms and other measures employed as a means to increase market prices for energy, ancillary services and installed capacity, and to manipulate the prices for transmission rights. However, these attempts have been more sporadic and have had a far less significant economic impact than California. This is due in part to the fact that approximately 85 percent of demand is covered under long-term contracts and therefore is unaffected by spot price volatility. In general, the Eastern markets are considered relatively competitive and have a range of measures in place to monitor and mitigate locational market power.[45] Several problematic markets, especially for installed capacity, have been eliminated or substantially modified. In addition, at least some types of market manipulation that have occurred in the New England market are associated with its interim market design, and will not recur under the Standard Market Design. Similarly, in New York, many initial poor design decisions and software choices made within a framework similar to the proposed Standard Market Design have been modified and improved, yielding some lessons for future attempts to implement Standard Market Design markets.[46]

The previous section examined whether the Enron strategies in California could be used to manipulate prices under the Standard Market Design. This section reviews some of the publicly known examples of market manipulation in the Eastern ISO markets and

[45]Each of the Eastern ISOs produces reports on market performance and on market power monitoring and mitigation. These reports are available on the ISO web-sites; particular reports referenced in this section will be cited. In addition, filings before the Commission and Commission orders address these issues and will also be cited when referenced. See also FERC, "Investigation of Bulk Power Markets: Northeast Region," November 1, 2000, available on the FERC web-site; State of New York Department of Public Service, "Interim Pricing Report On New York State's Independent System Operator," Department of Public Service Pricing Team, December 2000.

[46]David B. Patton and Michael T. Wander, "2001 Annual Report on The New York Electric Markets," Independent Market Advisor to the New York ISO, June 2002.

discusses whether and how the Standard Market Design would prevent such activity.[47] The ISO market monitoring reports and filings before the Commission provide many further examples of market manipulation in the Eastern ISO markets that concern either minor events, transitory problems, or market rule changes made in anticipation of potential market manipulation. The Standard Market Design may not specifically require many of those rules, but the Commission will review Standard Market Design compliance filings to evaluate whether proposed market rules are susceptible to manipulation.

A. Energy Markets

The Eastern ISO energy markets have been subject to forms of market manipulation and market power, including both economic and physical withholding. Most exercise of market power in the energy markets occurs in two types of system conditions: (1) the existence of persistent transmission constraints in some locations and (2) periods of system-wide shortage of energy, such as exists on peak-load days or during emergencies. Locations that are on the import side of persistently congested transmission lines (sometimes called "load pockets") present the most opportunity for exercise of market power due to the high concentration that occurs in these locations. Generators in these locations are typically closely monitored and/or placed under contract to prevent bid price increases. Hence, this section will not consider market power in these locations.

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[47]Some paragraphs in this section are excerpted from FERC, "Investigation of Bulk Power Markets: Northeast Region," November 1, 2000.

During capacity shortages or system emergencies, market power is more diffuse, reflecting the possibility that all generation will have to be dispatched. For example, the PJM market monitor believes that high energy prices in the summer of 1999 were the result of the interaction of high demand levels with supply curves that exhibited steep slopes over very narrow ranges of output. Some firms appear to have withheld capacity and changed bid parameters during peak hours as a means to drive up prices (see discussion below). However, these prices also appear to have attracted imports into PJM. The market monitor thus concluded that the high prices were due both to scarcity and to the exercise of market power, but that the relative importance of the two factors could not be determined.[48]

During periods of shortage, interactions between the energy markets and the markets for ancillary services and installed capacity are also more significant. Market power in each type of market can affect the other. Price increases in the energy markets will lead to higher prices for ancillary services, since the prices in the latter markets reflect the opportunity costs associated with forgone energy sales.[49] Maintenance of the operating reserve requirement can also drive up prices in the energy market, because the

[48]PJM Market Monitoring Unit (MMU), "PJM Interconnection State of the Market Report 1999," June 2000. The report explains that long-term net revenue results indicate that prices were competitive in 1999.

[49]The standard pricing rule for regulation and operating reserves is to compensate generators that would have been scheduled for energy but are withheld for regulation or reserves for the forgone energy revenues. This pricing rule is continued in the Standard Market Design.

ISO markets require that all energy should be taken to preserve the reserve margins prior to having to reduce them (see example 1(a), below); hence withholding of reserves could drive up not just reserve prices but also energy prices.[50]

1. Manipulation of physical bid parameters to extend the operating time or increase the output level of a generator and increase the market price – Several ISO markets have experienced firms' use of the bid-in physical parameters of generators, such as minimum run times and low operating levels, to extend the operating time and/or output of the generator and possibly set a higher market clearing price than was economically necessary. Typically, these problems are combined with specific market rules that allow the change in physical bid parameters to impact the price (under a purely competitive market assumption, changes in these parameters should not affect the price in the market). Two specific cases follow.

(a) In PJM, certain generators were increasing their minimum run times to the full 24 hours of the day and submitting high price bids. Under the PJM energy market rules, the bids were evaluated over the full day; hence, under normal conditions, high price bids would be rejected. However, in Maximum Generation

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[50] In addition to the example in 1(a), there are some significant instances in which the reliability rules that require ISOs to purchase energy from any external or internal source to maintain the reserve margin can increase the energy price. For example, prior to the imposition of the $1000 energy bid cap in the Eastern ISOs, ISO New England experienced an $6000/MWh energy clearing price for four hours in May 2000 due to an import purchase that was taken to avoid degrading the internal reserve margin. However, this case was not deemed to be exercise of market power. See FERC, "Investigation of Bulk Power Markets: Northeast Region," November 1, 2000.

Emergencies, PJM was required to take all economic offers, regardless of the number of hours of the day in which such offers were economic, prior to taking other emergency measures, such as recalling capacity resources. This allowed these generators to run at a high price all day and set LMPs higher than the $1,000 bid cap. PJM estimated that in 1999, excess energy payments to just one plant of $8 million resulted from this bidding technique. The Commission approved PJM's market rule revision to address this problem, which restricted the bid sufficiency guarantee only to the hours in which the generator bid was economic during the emergency.[51]

Under the proposed Standard Market Design market rules, as in PJM, a generator's bid offer must be considered over the full day. Hence in normal circumstances, as in PJM, changing the generator's minimum run time should not confer any competitive advantage. The Standard Market Design rules explicitly require that the Transmission Provider must evaluate how emergency conditions affect market prices. In complying with this requirement, the Commission will evaluate whether the rules prevent market manipulation, whether by adopting the PJM rules or some other measures.

(b) In New England, generators were bidding very high low operating levels – that is, setting a high minimum output level. By the existing rules in New England, these generators were not eligible to set the Energy Clearing Price but were eligible for uplift payments based on their bid. The ISO proposed, and the

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[51]See PJM Interconnection, L.L.C., 92 FERC ¶ 61,013 (2000).

Commission accepted, that generators would be required to bid their physical low operating levels, subject to adjustment for emissions or economic efficiency reasons.[52] This kind of problem would be less likely in an LMP-based system with a revenue sufficiency guarantee.

Under Standard Market Design, the Transmission Provider is given authority to put limits on the frequency with which physical bid parameters can be changed, and other limits on how the operating characteristics of the generators are bid. These potential bid restrictions can be used to address any evidence of market manipulation or to anticipate such behavior.

B. Ancillary Service Markets

Bid-based ancillary service markets typically have fewer eligible suppliers (particularly until demand-side resources participate) than the energy markets as well as inelastic demand (unless demand curves for reserves are established). Locational reserve requirements may narrow the markets further. Finally, as noted above, market power in the energy markets is transferred to the ancillary service markets through opportunity cost payments and other market rules.[53] These factors make monitoring of these markets important. Under normal conditions, it is expected that regulation and operating reserves should account for under 10 percent of total market costs, and in the Eastern ISO markets

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[52] See ISO New England, Inc., 99 FERC ¶ 61,124 (2002).

[53] PJM Market Monitoring Unit (MMU), "PJM Interconnection State of the Market Report 2001," PJM Interconnection, L.L.C., June 2002, p. 108.

are often under 5 percent. In contrast, in a few cases, poorly designed ancillary service markets and/or exercise of market power in these markets have resulted in ancillary services temporarily accounting for a much higher percentage of total electricity costs.[54]

1. Withholding of Operating Reserves – The New York ISO markets for operating reserves experienced withholding of operating reserves in the Spring of 2000, resulting in substantially higher prices for these products for several months.[55] In particular, ten-minute non-spinning reserves were both withheld from the market physically or bid in at a high level by the three major suppliers. The high price for this reserve in turn drove up prices for regulation and the other operating reserves. In response, the Commission approved a bid cap on ten-minute non-spinning reserves and the New York ISO took additional measures to increase supply.[56] The Commission subsequently imposed a bid cap on non-spinning reserves in the ISO New England markets for similar reasons.[57] PJM delayed the start of a ten-minute spinning reserve market in part due to concerns about the potential for limited sellers of the product.

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[54] For example, New York ISO experienced one month, February 2000, in which regulation and operating reserves accounted for almost 30 percent of total market costs. This was an aberration due to the market power in the reserves markets discussed in example (1); following market power mitigation measures, the costs of these ancillary services dropped to under 5 percent of total market costs. See Patton, David B., "New York Market Advisor Annual Report on The New York Electric Markets for Calendar Year 2000," ISO New York, April 2001, p. ix.

[55] See id.

[56] New York Independent System Operator, Inc., et al., 91 FERC ¶ 61,218 (2000).

[57] See ISO New England, Inc., 99 FERC ¶ 61,124 (2002).

As in the energy markets, Standard Market Design auctions alone cannot solve structural sources of market power in the regulation and operating reserves markets. Rather, these problems must be addressed through a combination of market power mitigation measures, such as bid caps, and structural solutions, such as encouraging entry into these markets by generators with flexible start-times.

C. Congestion Management Systems and Transmission Rights

The congestion management system based on LMP and financial transmission rights proposed in the Standard Market Design and in use in PJM and New York presents a clear advantage over the transmission line-loading relief (TLR) methods used in other parts of the country. The LMP-based method has caused far fewer instances of transmission curtailments.[58] At the same time, any transmission network with congestion pricing and financial transmission rights is susceptible to some degree to market manipulation.[59] Heretofore, there has been some evidence of manipulation of these design elements in the Eastern ISO markets, although nothing that has disrupted the markets. Nevertheless, under Standard Market Design, such behavior will be monitored for and mitigated if found.

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[58] See, e.g., FERC, "Investigation of Bulk Power Markets: Southeast Region," November 1, 2000; and FERC, "Investigation of Bulk Power Markets: Midwest Region," November 1, 2000.

[59] Although electricity flows in complex patterns determined by physical laws and subject to the simultaneous interaction of all injections and withdrawals on the systems, the ways in which generators load certain lines can be calculated (through so-called "generation shift factors") or understood through experience.

Care must be taken to discriminate between legitimate transactions and those aiming to favor owners of certain generation or transmission assets. Increasing congestion is not necessarily a sign of intentional activity to congest; all the Eastern ISOs report increasing congestion as market trading increases simply because there is more demand for distant resources and associated transmission. In addition, changes in congestion accounting may increase the amount of apparent congestion[60] and transmission maintenance or outages can also have a major effect.

An important financial linkage in the Standard Market Design is between the congestion management system and the holding of Congestion Revenue Rights. The Standard Market Design rules aim to find a method of allocation, trade and settlement of such rights that is equitable, transparent, provides appropriate incentives for maintenance of and investment in transmission assets, and is resistant to manipulation. The following example shows how market manipulation can occur.

1. Sharing of information about Transmission Maintenance by Transmission Owners to affect the value of affiliates holdings of Transmission Rights – In PJM, information acquired during a non-public investigation suggested that subsidiaries of Exelon, may have shared information that gave the marketing subsidiary

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[60]For example, PJM reports a notable increase in congestion over low-voltage facilities, which is at least in part associated with PJM assuming monitoring and control of these facilities from transmission owners. See PJM Market Monitoring Unit (MMU), "PJM Interconnection State of the Market Report 2001," PJM Interconnection, L.L.C., June 2002, p. 126.

an informational advantage in its bidding for Fixed Transmission Rights (FTRs) in the monthly FTR auctions. After the bidding closed in three auctions held in September, October, and November 1999, PECO announced maintenance outages on transmission facilities within PJM. The Commission directed Exelon, PECO and Exelon Power Team to show cause whether they violated section 205(b) of the Federal Power Act (FPA) and the standards of conduct and the Commission's regulations by operating PECO's transmission system in an unduly preferential manner or sharing non-public information regarding the timing and location of maintenance outages in PJM's system or both. The Commission also directed PJM to report, to the Commission on its current transmission oversight processes and procedures regarding maintenance and de-rating decisions.[61] PJM subsequently modified its transmission oversight procedures to eliminate incentives for such behavior.[62]

This problem is generic to electricity markets with transmission rights. The rights established under Standard Market Design, which include financial rights analogous to FTRs in PJM, are susceptible under some conditions to manipulation by transmission owners and their affiliates. The Standard Market Design requires market monitoring and appropriate transmission maintenance oversight and incentives to mitigate such problems.

D. Installed Capacity Markets

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[61] See PJM Interconnection, L.L.C., 97 FERC ¶ 61,010 (2001).

[62] See PJM Interconnection, L.L.C. "Report of PJM Interconnection, L.L.C. on Transmission Oversight Procedures, Docket No. EL01-122-000 (November 2, 2001).

Each of the Eastern ISO markets has an installed capacity requirement and an ISO-operated capacity market (with the exception of New England, in which the market was terminated). The design of these markets is different in each ISO, as is the market structure (that is, the degree of firm concentration in the market); hence, the problems experienced in each market have also been different. As discussed in this proposed rule preamble (Section H), for various reasons the proposed Standard Market Design includes a resource adequacy requirement similar in purpose to what is called here "installed capacity" but does not include either specific rules for a tradable capacity product or a centralized market to provide such adequacy. However, regions may choose to establish such markets. This section discusses some of the market manipulation that has been experienced in the existing ICAP markets. The Commission will evaluate any proposals for new markets for resource adequacy on the basis that they do not result in a repeat of the flaws detected in the existing ISO installed capacity markets.

1. Bid Manipulation of poorly defined ICAP products (New England) – The original ISO New England ICAP market was recognized as a flawed market almost from its inception (along with other aspects of the New England markets),[63] but the true

[63]The preliminary New England market design was developed by NEPOOL committees over the course of 1998. Problems with this design were suggested by independent experts under contract to the ISO (See Peter Cramton and Robert Wilson, "A Review of ISO New England's Proposed Market Rules," Report to ISO New England, Market Design Inc., September 1998). However, these experts, the ISO and NEPOOL supported beginning market operations and addressing market design problems with the markets in progress. NEPOOL proposed a phased implementation which was approved (continued...)

problems and attempts at market manipulation did not emerge until several months into operations. The basic flaw was that the ICAP product did not have any recall obligations or deliverability requirements and had only seasonal availability requirements. Hence, its value in the monthly auction was determined not by the value of ICAP but by the ability to manipulate the price. The auction clearing price tended to swing between $0/MW and very high prices. In early 2000, the ISO determined that the ICAP price was due to market power and revised the price for several months.

The subsequent modifications of the New England ICAP requirements and markets will not be reviewed here. In a June 28, 2000, order, the Commission agreed with the ISO that the existing installed capability auction market was not useful and that it could produce inflated prices unrelated to the actual harm created by installed capability deficiencies.[64] The Commission permitted the elimination of the auction market effective August 1, 2000, and required the ISO to revert to administratively-determined deficiency charge for failure to meet installed capability requirements.

2. Withholding of ICAP (PJM) – In the ICAP markets in PJM and New York, both structural problems and market design issues have resulted in ongoing refinement of market design and measures to limit the exercise of market power. An in-

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[63](...continued)
by the Commission. Market trials were run in January 1999 and the markets were started on May 1, 1999.

[64]See ISO New England, Inc., et al., 91 FERC ¶ 61,311 (2000).

depth explanation of the designs of these markets is beyond the scope of this section; rather, the focus will be on the exercise of market power in the PJM daily capacity credit market in early 2001. The PJM market monitor has noted potentially high concentration and design flaws in this market since its inception on January 1, 1999, and there have been modifications of the market rules several times.

In PJM, each load-serving entity has the obligation to own capacity, have a bilateral contract for capacity, or purchase capacity credits through a centralized market equal to its peak load plus a reserve margin. To qualify as a capacity resource, a generating unit must pass tests regarding overall capability and the ability to deliver energy to PJM load, which requires adequate transmission capability. Load-serving entities can use their capacity resources to produce energy for export from the PJM control area, but such transactions are subject to recall by PJM in emergencies. If a load-serving entity's capacity resources are less than its obligation, then it is considered deficient and subject to a penalty. In 2001, the capacity credit market was operated on a daily, monthly and multi-monthly basis as well as on an "interval" basis defined by seasons (the daily market serves residual demand after the markets for longer-term credits close).

Between January and April 2001, a single firm raised the price in the daily capacity credit market for a sustained period of time by essentially being in a position that required all buyers that were short of capacity to have to purchase some or all of their capacity from it. The determination that this price increase was the exercise of market power through economic withholding was made on the basis of the excess capacity available at the time as well as calculation of the opportunity cost of that capacity, which is the sale of the firm energy output forward into a neighboring market. Effective June 2001, the Commission approved market rule changes that diminished the incentive to economically withhold by spreading the revenues accruing to owners of excess capacity to all compliant load-serving entities rather than to the single firm.[65]

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[65] See PJM Interconnection, L.L.C., 95 FERC ¶ 61,175 (2001).

APPENDIX F

Access Charges and Congestion Revenue Rights

Allocation of Congestion Revenue Rights

Phase I (initial allocation) – through direct assignment based on historical use

All existing customers using transmission service, whether through bundled contracts, service agreements under the pro forma tariff, or pre-Order No. 888 transmission contracts, pay the transmission rate, i.e., the access charge, which enables the transmission owner to recover the fixed, or embedded, costs of its transmission system. Moreover, the existing pro forma tariff grants priority for transmission capacity to existing long-term firm customers.

This proposed rule gives the region a choice between an initial allocation or an auction of Congestion Revenue Rights. The first portion, "Phase I," deals with regions that start with an allocation of Congestion Revenue Rights to existing long-term customers based on their historical use of the system. In this sense there is a link between paying the access charge and receiving Congestion Revenue Rights. However, this is not a one-to-one link, i.e., not all customers paying the access charge will receive Congestion Revenue Rights – customers with short-term or non-firm service under the existing pro forma tariff currently pay an access charge but would receive no Congestion Revenue Rights through the initial allocation process. This is consistent with Section 2.2 of the existing pro forma tariff, which grants rollover rights (which guarantee access to firm service) only to longer-term contracts.

<u>Phase I: Specific Examples – What the Customer Pays and What the Customer Gets</u>

The following answers the question of whether and how the following customers currently receiving various services will pay access charges or receive Congestion Revenue Rights. All service in the following examples would be performed under Network Access Service upon implementation of Standard Market Design.

A. Short-Term and Non-Firm Contracts (less than one year in duration) – These customers would receive no Congestion Revenue Rights (however, transactions under which power is taken off the grid pay an access charge; those under which power is not taken off the grid do not pay an access charge). These contracts would be converted to Network Access Service at the time Standard Market Design is implemented through the SMD Tariff.

B. Long-Term Contracts (one year or longer)

1. Existing Network Integration Transmission Service – These customers currently pay and would continue to pay the access charge, and would receive a direct allocation of Congestion Revenue Rights.

2. Existing Point-to-Point Service

a. Load-Serving Entity (service to load within a single Transmission Provider's area) – These customers currently pay and would continue to pay the access charge, and would receive a direct allocation of Congestion Revenue Rights.

b. Internal, Non-Load Serving Transactions (service within a single Transmission Provider's area from generator to hub, hub-to-hub, or to support sales to the spot market) – The customer currently has specific rights to capacity between stated points and, for this, pays the access charge. Under Standard Market Design, it would be permitted to retain its priority rights, albeit in the form of Congestion Revenue Rights rather than firm transmission capacity rights through Phase I. For this continued right, however, the customer must continue to pay the access charge to receive a direct allocation of Congestion Revenue Rights. In other words, it could choose to either (1) continue the point-to-point contract, including paying the access charge, and for that would receive a direct allocation of Congestion Revenue Rights; or (2) terminate the contract, meaning the customer would no longer pay the access charge, no longer receive specific transmission capacity rights between points, and, therefore, would not receive a direct allocation of Congestion Revenue Rights. Under the second choice, the customer would instead schedule service in the day-ahead and real-time markets and pay the applicable congestion and loss charges.

c. Through and Out (export by generator or marketer) – Consistent with internal, load-serving transactions (above), the customer currently has specific rights to capacity between stated points and, for this, pays the access charge, but would no longer be required to pay the access charge to export power to another region. It would be permitted to retain its priority rights, albeit in the form of Congestion Revenue Rights rather than firm transmission capacity rights through Phase I so long as it continued to pay an access charge on the source Transmission Provider's system. In addition, the access (or scheduling) charge paid by all load-serving entities taking power off of the grid on the sink side of a transaction involving two Transmission Providers' systems would include a portion of the transmission costs from the source side of the transaction, as explained below.

3. Existing Pre-888 Transmission Contract – These contracts are not standard and may have characteristics of Network Integration Transmission Service or Point-to-Point Transmission Service. Customers currently pay an access charge (though likely a different charge than under the pro forma tariff). In either case, the load-serving entity (the transmission owning public utility who currently is the transmission provider), would pay the Transmission Provider the access charge on behalf of the pre-888 customer, and would receive any direct allocation of the Congestion Revenue Rights associated with the contracts, unless the customer converted its contract to Network Access Service. Continued payment of the access charge and direct allocation of Congestion Revenue Rights would be based on the nature of the service and would be determined consistent with the pattern established above.

4. Bundled Wholesale Contract – Like pre-888 transmission contracts, these contracts are not standard and may have characteristics of Network Integration Transmission Service or Point-to-Point Transmission Service. Customers currently pay an access charge (though likely a different charge than under the pro forma tariff). Like the pre-888 contracts, the load-serving entity (the transmission owning public utility who currently is the transmission provider), would pay the Transmission Provider the access charge on behalf of the bundled wholesale customer, and would receive any direct allocation of the Congestion Revenue Rights associated with the contracts, unless the customer converted its contract to Network Access Service. Continued payment of the access charge and direct allocation of Congestion Revenue Rights would be based on the nature of the service and would be determined consistent with the pattern established above.

5. Bundled Retail Customers – There is no specific contract defining transmission rights for this type of service. Customers currently pay an access charge through the bundled rate. The load-serving entity, often the transmission owning public utility who currently is the transmission provider, would pay the Transmission Provider the access charge on behalf of the bundled retail customer, and would receive a direct allocation of the Congestion Revenue Rights.

6. Retail Choice – Customers in states with retail choice are either transmission customers under the pro forma tariff, or they are buying power from a supplier who is acting as the transmission customer on their behalf. They currently directly (or indirectly through the supplier) pay the access charge. The transmission customer in these transactions would receive the direct allocation of Congestion Revenue Rights. However, if the retail customer switched suppliers, this proposed rule establishes the principle that the Congestion Revenue Rights move with the load (i.e., the

Transmission Provider would have to periodically reallocate the Congestion Revenue Rights based on each load-serving entities' load ratio share).

Phase II (within four years of adoption of Standard Market Design) – through an auction

Under Phase II, Congestion Revenue Rights (other than those assigned to an entity on a "life of the facility" basis as a result of the customer paying for the network upgrades) will be auctioned off rather than allocated to particular customers. The link between paying the access charge and receiving Congestion Revenue Rights will no longer exist once we move to a full auction, since any entity can acquire Congestion Revenue Rights through the auction, with no requirement to pay an access charge to get them. Instead, the link moves to the revenue side, i.e., the auction revenues would be returned to those customers paying the embedded costs of the system through an access charge.

Are there differences in the allocation of Congestion Revenue Rights based on how the rates are paid?

1. Service with rate based on open access tariff's embedded cost charge

a. At the time of direct allocation – this is defined above (long-term customers pay the access charge and get the direct allocation of Congestion Revenue Rights)

b. At the time of the auction – this is defined above for various categories of customers (some customers will continue to pay the access charge, which will be reduced by auction revenues, but all Congestion Revenue Rights will be auctioned)

2. Service with rate based on incremental cost of new transmission facilities

a. At the time of direct allocation – When a customer requests firm service under the existing pro forma tariff and network upgrades must, on occasion, be built to accommodate the service. The Commission has historically allowed rates for transmission service to be set at the higher of the incremental cost or the average embedded cost. Thus, the allocation of Congestion Revenue Rights for customers who are currently paying an incremental rate for transmission service will, therefore, be the same as for customers paying the embedded cost charge under the pro forma tariff for transmission service.

b. At the time of the auction – Under Standard Market Design, customers generally will no longer request to build facilities to receive "firm" service, since all service will be allocated based on the customer's willingness to pay congestion costs. Rather, customers will request an economic expansion in order to avoid paying the cost of congestion. For economic expansions that are not rolled in to the embedded cost charge, the customer will pay the Transmission Provider the cost of the new facilities in order to acquire the Congestion Revenue Rights, and will continue to pay the access charge to receive Network Access Service.

3. Economic Expansions – once an Independent Transmission Provider is in place, it (with state participation) would make a decision on pricing. Most likely, the beneficiary(ies) of the economic expansion of the network would pay for the cost of the new facilities in return for any Congestion Revenue Rights created by an increase in transfer capability, and will continue to pay the access charge to receive Network Access Service. Otherwise, all network expansions would be rolled in either regionally or to a license plate zone and, therefore, all newly created Congestion Revenue Rights would be auctioned.

4. Reliability Expansions

a. At the time of direct allocation – reliability expansions benefit all users of the grid; therefore, the costs are rolled-in to the access charge either regionally or to a license plate zone. Accordingly, any newly created Congestion Revenue Rights associated with the expansion will be auctioned.

b. At the time of the auction – the introduction of the full auction would have no impact on reliability expansions, which will continue to be rolled-in either regionally or to a license plate zone with any newly created Congestion Revenue Rights associated with the expansion offered in an auction.

5. Generator that receives credits for network upgrades

a. At the time of direct allocation – currently, the interconnecting generator pre-pays for transmission service and receives credits against the monthly cost of transmission service, whether the generator is the customer or it is chosen as a network resource by a load-serving entity. To the extent the generator is a long-term transmission customer, it would receive Congestion Revenue Rights associated with its transmission service (otherwise the network customer that chose the generator as a network resource would receive the Congestion Revenue Rights).[66] If participant funding is adopted, the customer would receive the Congestion Revenue Rights associated with the additional transfer capability made possible by the transmission expansion. This pricing is subject to the outcome of the Generator Interconnection proposed rule in Docket No. RM02-1-000.

b. At the time of the auction – a generator would be treated in the same fashion as other customers under the pro forma tariff both with respect to payment of the access charge and receipt of Congestion Revenue Rights. If participant funding is adopted, the customer would receive the Congestion Revenue Rights associated with the additional transfer capability made possible by the transmission expansion. This pricing is subject to the outcome of the Generator Interconnection proposed rule in Docket No. RM02-1-000.

6. Merchant transmission owner

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[66]There could be situations where the transition to Network Access Service occurs prior to a customer receiving transmission credits it is entitled to. To the extent that such a customer would no longer be required to pay the access charge, we would expect the RTO or Independent Transmission Provider to return the remaining amounts to the customer at the same rate as if the current transmission charge were still in place until the balance is returned.

a. At the time of direct allocation – A merchant transmission owner does not receive service, but rather is a transmission owner. A customer using this facility would also have to pay for service across the RTO plus a rate for service on the merchant facility. Accordingly, the merchant transmission owner would pay for the full cost of constructing the new facilities and would receive the Congestion Revenue Rights associated with its facility for the economic life of the facility. The full amount of those rights may be subject to change based on changes in the overall grid over time (e.g., changes in flow patterns or deterioration of transfer capability of other lines may diminish the amount of Congestion Revenue Rights associated with the merchant facility).

b. At the time of the auction – the introduction of the full auction will not change the way merchant facilities are addressed – the merchant transmission owner would pay for the full cost of constructing the new facilities and would receive the Congestion Revenue Rights associated with its facility for the economic life of the facility.

Cost Shifts due to Eliminating the Access Charge for Inter-Regional Transfers

This rulemaking proposes to eliminate transaction fees (the access charge) on through and out transactions. This, by definition, raises the possibility of cost shifts, resulting in winners and losers. This scenario has been previously faced and resolved within a Transmission Provider's service area, with the result being the elimination of pancaked rates, and can be resolved across multiple service areas as well.

Currently, all transmission customers pay a share of the embedded costs of the transmission system. Under Standard Market Design, only load-serving entities (i.e., customers taking load off of the grid) will pay a share of the embedded costs of the system through an access charge.[67] This means that the portion of embedded costs currently paid by customers transmitting power through or out of a Transmission Provider's service area must be picked up by load-serving entities. However, while this may seem like a rate increase, the benefits from the elimination of the interregional access charge should exceed the costs. Specifically, this occurs through the reduction in generation costs across the region, as we will explain below.

Current situation on a hypothetical RTO (or transmission provider's system): 90 percent of the embedded costs are paid for by bundled retail customers, network customers, and point-to-point customers who serve load within the RTO. 10 percent of the embedded costs are paid for by point-to-point customers exporting power to another RTO or moving power within the RTO but not to load.

Standard Market Design will have two transmission rate impacts: First, the non-load serving transactions will no longer pay the access charge. Second, the inter-regional transfers will be netted across RTOs and the load-serving entities on the net importing RTO will pay a load ratio share of the embedded costs of the exporting RTO. On first blush, it would appear that the load-serving entities on both RTOs will pay more of the

[67] This may also include point-to-point customers who continue to pay the access charge to receive Congestion Revenue Rights.

embedded costs to make up for the fact that exporting generators will no longer pay an access charge. While this is true with respect to transmission costs, it ignores the intended benefit of this rate change – lower generation costs.

First, access charges paid by generators for the first leg of a transaction, whether to serve load in the same or a neighboring RTO, are ultimately paid by the purchaser of the power. So, recovering these costs directly from the load-serving entities will not increase the overall cost of delivered power.[68]

More importantly, removing this additional transaction fee reduces the cost of reaching generation on a neighboring RTO. The removal of the transaction cost makes cheaper generation available across a broader area, which leads to a more optimal dispatch and lower generation cost for all customers.

For example, assume load is served at a particular location in RTO A at an LMP of $25, and that there is a generator on neighboring RTO B willing and able to sell at $24 (i.e., it has available capacity and there is no transmission constraint between the sink and source). However, RTO B has an access charge of $2, making the competing generator's delivered cost non-competitive at $26. Removing the $2 transaction fee reduces the generator's delivered cost to $24, saving all customers at that location $1, since the LMP is reduced from $25 to $24. Moreover, to the extent that other load within RTO A is

[68] It is possible that there will be instances where a bundled purchase contract, if not reformed to reflect this change in transmission rate design, will result in the customer paying twice for transmission service. Affected customers could file under section 206 of the FPA to seek to reformation of their contracts.

served with generation cost in excess of $25, the $25 generator in RTO A that was displaced by the $24 generator in RTO B is now available to meet this load, providing greater generation savings across RTO A. Given that generation costs far exceed access charges, customers' overall savings (generation plus transmission costs) can be reduced far below the increase in transmission costs resulting from the elimination of the access charge on inter-regional transactions. There could be additional savings to the load-serving entities in that they would receive additional Congestion Revenue Rights (or the associated auction revenues) that would otherwise be held by the point-to-point customers.

The precise details of how current contracts will be transitioned and how embedded transmission costs associated with inter-regional transactions will be netted across regions should be left to regions to work out in compliance filings.

APPENDIX G

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

Date: ________________________

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

From: ____(organization name)

____(organization address)

____(organization address)

____(organization address)

This organization certifies the following items regarding FERC security standards for grid-market systems, as of this date:

Compliant	Non-Compliant	Does Not Apply	
☐	☐	☐	Management assignment of grid-market system security.
☐	☐	☐	Security Perimeter defined and documented.
☐	☐	☐	Security Program and Policy developed and documented.
☐	☐	☐	Policy, standards, and procedures reviewed at least annually.
☐	☐	☐	An Asset Classification system defined and implemented.
☐	☐	☐	Security training requirements for personnel with access to critical assets have been met.
☐	☐	☐	All personnel receive security awareness training at least annually.
☐	☐	☐	Critical asset administrators and operators have had background screening within last five years.

☐	☐	☐	Access control procedures for authorized personnel are implemented.
☐	☐	☐	Unauthorized personnel inside security perimeter are escorted at all times.
☐	☐	☐	Cyber procedures for system security have been developed and implementation monitored for compliance.
☐	☐	☐	Physical procedures for system security have been developed and implementation monitored for compliance.
☐	☐	☐	Security requirements for developing and testing critical systems have been documented.
☐	☐	☐	Software development systems are not interconnected with operational systems.
☐	☐	☐	Incident response plans are implemented.
☐	☐	☐	ES-ISAC reporting and alert notification procedures are implemented.
☐	☐	☐	Business continuity plans are established and exercised.

Explanation for Non-Compliant Items:

Name: ____(print)

____(title)

____(signature)