

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

RTO Interregional Coordination

)

Docket No. PL01-5-000

**COMMENTS OF
PJM INTERCONNECTION, L.L.C.
ON TECHNICAL CONFERENCE**

As requested by the Commission, PJM Interconnection, L.L.C. (“PJM”) submits these additional comments on the issues raised by the technical conference held on June 19, 2001. In brief summary, these comments set forth that:

1. There are fundamental policy decisions that the Commission must make before the industry can move effectively to resolve seams issues. The opposing models that the Commission has tentatively endorsed for RTOs (markets vs. no markets; LMP vs. flowgate; financial rights vs. physical rights) will create incompatible regional markets with major obstacles to seamless trading. These obstacles will not be effectively resolved by mere mitigation around the edges, and the seams will endure absent further Commission action. After the Commission provides guidance on the fundamental policy issues, the industry will be able to take the lead in the seams resolution process.
2. An Energy Industry Standards Board (“EISB”), like GISB in the gas industry, can assist in developing commercial standards, but cannot “pick winners and losers” on fundamental market design issues. The Commission first must establish the policies that those standards will implement. If the Commission allows fundamentally different models to continue in different regions, there cannot be a single set of national standards covering all regions or even neighboring regions.
3. Once the Commission makes the policy decisions, a single national standards setting organization, which has independence, transparency, and market expertise, should take up the task of designing standard commercial practices, with the Commission’s oversight as a backstop.

I. The Commission Has Approved Fundamentally Different RTO Models For Different Regions And Thereby Created Seams.

“Seams” exist wherever adjacent grid managers have differing policies and practices. PJM has devoted considerable resources in recent years to resolving seams with its neighbors,¹ and will continue to give top priority to seams issues, in all their forms. As recognized repeatedly at the technical conference, seams complicate and increase the cost of transactions that use multiple facilities managed by different operators, and thereby impede wholesale competition. Tr. 14(Brockway – NE Regional ISO Coordination Conference); 44-45 (Heller – Transmission Access Policy Group). By approving RTOs, the Commission can reduce the number of grid managers nationwide and eliminate historic seams and other obstacles within regions. Tr. 31-32 (Harris – PJM).

For seams between RTOs, the Commission’s past precedent has contributed to their creation, and so the Commission should now assist in their resolution. Although well-intentioned, the Commission’s policy of accepting different RTO models for different regions is the major source of the most difficult inter-RTO seams issues. See, e.g., Tr. 99 (Reed – Alliance of Energy Suppliers).

In Order No. 2000², the Commission stated its willingness to consider RTO proposals of many varieties. In particular, it did not require an RTO to operate a spot

¹ See, e.g., Tr. 16 (Brockway-NE Regional ISO Coordination Conference); Tr. 35-36 (Museler-NYISO) and Tr. 38 (Vanwelie-ISO-NE).

² Regional Transmission Organizations, Order No. 2000, FERC Stats and Regs. ¶ 31,089 (1999), order on reh’g, Order No. 2000-A, FERC Stats and Regs. ¶ 31,092 (2000), pet. for review pending sub nom. Public Utility Dist. No. 1 of Snohomish County v. FERC, Nos. 00-1174, et al., (D.C. Cir. Apr. 24, 2000).

energy market to manage congestion.³ Because RTO models in fact were expected to be “quite varied,” the Commission left it to each region “to determine whether there is a need for a power exchange and whether the RTO should operate the power exchange.”⁴ As a result, today there are seams between those RTOs that operate spot markets and those RTOs that steadfastly eschew any responsibility for establishing regional spot markets.

While accepting RTO proposals both with and without associated spot markets, the Commission at the same time directed RTOs to have both imbalance mechanisms and “market-based” congestion management.⁵ Yet, the Commission made imbalance mechanisms a necessary “day one” issue, while allowing congestion management models to wait until a year following RTO startup. Id.

As Professor William Hogan stated at the conference, managing imbalances and managing congestion are fundamentally intertwined. “These are the same problem.” Tr. 208 (Hogan). They are both best managed by a regional spot energy market that is closely intertwined with the provision of regional transmission service. Yet, the Commission has given no guidance or direction as to whether the same mechanism must be used for imbalance and congestion management. And, it has not indicated whether spot markets will be required to manage imbalance and congestion. Left to their own

³ Id. at 31,206-07.

⁴ Id. at 31,207.

⁵ Id. at 31,128.

devices and without direction, different RTOs are addressing these matters in fundamentally different ways, creating major seams.⁶

Seams exist because of these differing, Commission-approved RTO designs. An RTO with a spot market that manages congestion and imbalances and an RTO without an associated market require markedly different rules and procedures to run the grid and manage the transactions on it. Most significantly, the RTO with an associated market can assure market participants that their transactions will not be curtailed so long as they commit to pay the market-based congestion cost. This permits financial hedging and promotes market certainty. However, where a market participant's transaction also involves an RTO without an associated market to manage congestion, the participant cannot effectively hedge the transaction and the market certainty is lost. The market participant's focus is and should be on its transaction, rather than on the number of transmission providers involved. But where there is no market solution available for one component of the transmission service, then there is no market solution available for the transaction as a whole.

While market participants desire common rules and procedures, the differing designs do not allow for common rules. By necessity, the RTO with a closely associated market for imbalance and congestion management and the neighboring RTO without an

⁶ In the case of for-profit transcos, it is generally recognized that, to avoid any appearance of conflict due to the locational energy prices that could determine the value of their transmission service, they should not operate spot markets. Other independent entities, therefore, will have to operate the regional energy market where a transco is the transmission provider. For example, some RTOs are being established as side-by-side ISOs and transcos. See, e.g., New England Transmission Owners, et al., "Joint Petition for Declaratory Order to Form the New England Regional Transmission Organization," Docket No. RT01-86-000 (filed Jan. 16, 2001), at 25-26.

associated market will require different business rules, different data, and different information at different times in order to run the grid efficiently, competitively, and reliably. For example, if a region uses a market to manage congestion, the market participant can specify in advance that it will pay the market-based congestion charge, and then can rely on the expectation that its transaction will go forward, without further action by the market participant. By contrast, where a region relies predominantly on NERC tagging and transmission loading relief (“TLR”) to manage congestion, then the transaction may be curtailed after it is scheduled, requiring further, and possibly repeated, intervention by the market participant. Indeed, the uncoordinated responses of curtailed participants in multiple bilateral deals could create congestion elsewhere and require another round of curtailments and further re-scheduling by market participants. This fundamental difference in the two approaches creates an unavoidable seam for participants wishing to transact in both regions. It is not that the RTOs do not want to resolve this seam; it is that their fundamentally different RTO designs simply require different rules and procedures.

Albeit well-intentioned, the Commission’s permissive approach to differing RTO designs created this seams dilemma. It will take the Commission’s help to eliminate the seams that are attributable to differences in fundamental design. While it may be a difficult decision, the Commission will have to decide whether to require spot markets to manage congestion in all RTOs, thus eliminating a fundamental seam between neighboring RTOs today. Or, the Commission can continue to allow RTOs to operate without associated energy markets, but must then recognize that differing business practices and seams therefore cannot be eliminated.

If the Commission wants to eliminate seams, it likely must establish a standard market design to be implemented on all sides of the nation's seams, rather than continue to allow RTOs to proceed in all directions. This does not mean that there cannot be some regional adjustments and enhancements. But, if seams are to be effectively eliminated, all RTOs must operate the same basic type of markets and offer the same basic services and products. "Good coordination cannot overcome bad market design." Hogan presentation at 1. "Coordination of congestion management and real-time pricing would provide improved market tools for managing transmission use and one-stop shopping for market participants." Id.

In the Northeast, market participants are already moving toward adoption of a single market design. ISO New England, Inc. ("ISO-NE") has announced that it will adopt a "standard market design," i.e., "a common energy market and transmission congestion design . . . based on the successful PJM model." Tr. 39 (Van Welie – ISO-NE) The PJM market participants have stated that they are willing to make the standard market design available to others at nominal, incremental costs. Tr. 61-62 (Harris – PJM). Moreover, "the model for regional planning that New England has adopted and New York has filed . . . is the PJM regional planning model [which] will have all three of the [Northeast] ISOs operating under the same regional planning protocol." Tr. 36 (Museler – NYISO)

II. The Commission Must Resolve The Policy Issue Concerning the Operation of Markets As Well As Several Other Basic Questions Before the Industry Can Develop National Standards for Business Practices.

To facilitate industry standardization efforts and promote seamless trading, the Commission should address and resolve a number of regulatory policy and market design

issues, including the following basic questions, for the reasons explained more fully below:

- The Commission should require that each RTO must have an associated regional energy market with locational pricing to resolve imbalances and transmission congestion.
 - The Commission should resolve whether market participants can be limited to submitting only “covered” schedules or instead can rely on imbalance markets to cover their schedules.
 - The Commission should resolve the fundamental policy question of what type of transmission service an RTO should offer.
 - The Commission should decide whether losses should be provided physically or financially.
- A. A Consensus Group Is Ill-suited to Resolving Fundamental Policy Issues, as the Commission Previously Found with GISB.**

At the conference, the Commission indicated an interest in spurring the formation of a consensus industry group to develop business practice standards to eliminate interregional seams, much as the Gas Industry Standards Board (“GISB”) developed standard business practices for interstate gas pipelines to promote seamless cross-pipeline transactions. Before embarking on this course, however, the Commission needs to recognize its limits, and acknowledge the difference between the matters addressed successfully by GISB and the more fundamental issues at the root of the seams problems facing regional grid operators.

Mr. William Boswell, Chairman of GISB’s Board of Directors, emphasized that GISB “avoid[s] like the plague” any “[p]icking [of] winners and losers” and that “anything that smacks of that has been precisely the thing that’s eventually come up to the FERC for decision.” Tr. 194 (Boswell – GISB). As Mr. Boswell explained, “there are a few things over the years that we simply said to [FERC], we can’t do that because

you have to make that call. We can't make that call because you're going to pick a winner or a loser." Id.

The Commission recognized as much in its orders on GISB. In Order No. 587-G, for example, the Commission observed that "it is only to be expected that a standards organization composed of representatives from every facet of the gas industry would disagree over the need for standards in certain areas, particularly where the disputes center on regulatory policy decisions."⁷ The Commission therefore accepted the burden of "addressing the disputed policy issues so that the industry can move forward and develop the standards needed to further integrate the pipeline grid." Id. The Commission accordingly proceeded to decide the relative service priority of intra-day nominations, whether to require pipelines to enter into operational balancing agreements and to permit imbalance trading, and whether to require all transactions to be conducted on the public Internet. Id.

Chairman Thomas Welch of the Maine Public Utilities Commission testified that there are several such fundamental policy decisions raised for the electric industry and that the Commission should address them in the first instance: "[T]here is another set of issues--congestion management falls roughly in this category; design of capacity markets falls roughly into that category--in which the near-term financial prospects of the market participants are going to vary greatly, depending on which result occurs. . . . Getting people . . . in the same room is not going to come out with a solution. . . . [O]n those kind of decisions, FERC needs to educate itself quickly with respect to the regional situations and just make a decision . . . not wait for the participants to come to their own resolution

⁷ Standards for Business Practices of Interstate Natural Gas Pipelines, Order No. 587-G, FERC Stats, and Regs. ¶ 31,061 (1998).

and not send it back to them to come to a resolution, because it won't happen." Tr. 203-04 (Welch).

Without policy guidance on the fundamental issues, the standard-setting process is likely to break down and become a debate on economic policy, not standards. Each group of market participants will press for a "standard" that advances its own economic agenda. That would be an unproductive process and highly unlikely to result in consensus standards.⁸

In short, before the industry can address standardized business rules for transactions across RTO regions, there must be a clear understanding of the transaction model that the standards will be designed to implement. Fundamentally, this means that the Commission must resolve several important framework or policy issues before any successful effort in this regard can be undertaken. PJM identifies several of these issues below.

B. The Commission Can Best Contribute to the Goal of Seamless Trading by Resolving the Following Key Policy Issues.

1. The Commission should require that each RTO must have an associated regional energy market with locational pricing to resolve imbalances and transmission congestion.

As Professor Hogan stated at the technical conference, the time has come for the Commission to state, as a matter of national policy, that there is a presumption that the

⁸ The extended debate and market dissatisfaction with NERC TLRs is a good example of an issue that would defy consensus standard-setting. Under one model, where markets manage congestion, there is no need for TLRs. But where markets are not present, transmission providers demand TLR procedures. There is no satisfactory national curtailment standard that would meet the needs of both groups. The only way standards can be set is if the competing paradigms – RTOs with markets or RTOs without markets – are first resolved to arrive at a single framework.

standard market design used in the Northeast is the preferred means of managing imbalance and congestion. As Professor Hogan observed, the Commission knows that a market design that relies upon a bid-based, security constrained, economic dispatch with financial point-to-point transmission rights works. Tr. 183 (Hogan). As Professor Hogan testified, “[t]he notion that we are going to solve these problems simply or easily, or that it is going to emerge voluntarily, I just think is defied by the evidence. . . . This Commission in the United States is the one entity that has the capability and the authority to do something about it.” Tr. 200-01. Similarly, Mr. Charles Yeung, of Enron Power Marketing, observed at the conference that “[i]f an RTO has a very effective congestion management process, which allows the market to buy through the congestion and to manage it financially, that’s what the market wants. A lack of coordination between RTOs and congestion management schemes puts a lot of risk on the market.” Tr. 210 (Yeung – Enron). Indeed, even those that do not want to operate markets concede that the Northeast markets are designed correctly and work. Tr. 75 (Baker – Alliance Companies). This does not mean that the Commission should not consider other models. However, the Commission should place the burden of proof on those that do not want these demonstrably effective markets to operate in their regions.

By making this fundamental policy decision, the Commission itself would eliminate that which, without question, will be the primary cause of difficult and potentially insurmountable seams. Until it resolves this fundamental policy decision, the Commission simply cannot expect seamless trading across regions.⁹ See Tr. 184 (Hogan)

⁹ Moreover, by endorsing reliance on associated energy markets, the Commission would curtail a disturbing trend toward increased reliance on command and control structures, as opposed to market structures. For example, some of NERC’s current reliability standards are command-and-control solutions (such as

(“But if you don’t do that, you’re not going to be able to operate successfully. You’re not going to be able to coordinate successfully.”). By design, market participants will have to use one set of planning, scheduling, and dispatching rules in one region, and another set in a neighboring region, whenever the neighboring regions operate with markets on one side of a seam and without them on the other side.

2. There are no legitimate barriers to the reliance by other RTOs on regional energy markets with locational pricing to manage imbalances and congestion.

It would not be difficult for the industry to move to a single market design, if the Commission were to direct it. Contrary to the claims of some, there is nothing unique or special about the location-based congestion management markets operated in the Northeast. They are based on basic operating tools that the entire industry has been using for years. All that the Northeast does differently is open the unit commitment and dispatch systems to the rest of the marketplace, eliminating the cloud of secrecy. Those systems are also administered by an independent entity, enabling the operation of competitive markets without the perception of manipulation by the system operator.

PJM and its members already have indicated that they would make the basic market design available to the industry. Any region can then readily adapt it to its own circumstances, with such refinements or enhancements as it finds desirable.

PJM’s market design is based on fundamental principles of power system operations that all system operators, including existing vertically integrated utilities, use. Every utility in the world engages in regional planning, day-ahead unit commitment, and real-time economic dispatch. The PJM market is nothing more than the implementation

TLRs), not market solutions, simply because most participants in NERC standard setting today operate in areas without associated regional energy markets.

of these standard tools in an open and transparent manner, such that daily system operations are determined by the economic decisions of the market participants, rather than by the command and control of the system operator.

For example, every utility that owns generation runs some type of unit commitment algorithm to determine the generation that will be required to meet load the next day. They must do this in order to ensure reliability. PJM's market design does the same thing, but the generation bids of the market participants determine the unit commitments rather than the unilateral decision of the system operator. Market participants determine if and when they want their units to run by making economic offers to the market. PJM then matches the offers to load offers, or "clears" the market, while respecting transmission limits on the system. That is just what traditional utilities historically did, based on the economics of their units rather than offers from the marketplace.

Similarly, every utility has to match generation to load in real time, based on its decisions about the dispatch order of the units. PJM's spot market is nothing more than that, but the dispatch is based on the offers of market participants, rather than on the decisions of the utility.

Notably, there is no requirement to participate in the real-time spot market. The spot market allows market participants to choose between self scheduling of their generation units or bidding them into the spot market for dispatch. The spot market sends real-time price signals to everyone so they can make their own decisions, rather than having a system operator make the decisions for them. Again, the only significant difference from traditional utility-determined dispatch is that this model is open and lets the market participants into the process.

There is a fundamental misconception that the market model that PJM and others are planing to use will work only in the Northeast where traditional tight power pools have existed. To the contrary, Mr. Nicholas Brown of the Southwest Power Pool indicated that SPP is “headed toward locational based marginal pricing in terms of dealing with congestion management.” Tr. 79 (Brown – SPP). The market model will work anywhere that utilities have used traditional unit commitment and economic dispatch – in other words, everywhere. The model will work if those in control of the unit commitment and dispatch process are willing to give up their monopoly on scheduling and dispatch.

Nor, contrary to perception, does the market model require complex systems or software. The model is based on everyday tools used by utilities for decades. As Professor Hogan notes, the breadth of application and success of the framework dispel the notion that the model is too complex to be implemented. Hogan Presentation at 3.

Similarly, the regional planning process upon which PJM depends is not any different than historic planning tools used by traditional utilities. Every utility has had to engage in long term transmission planning. The only difference is that PJM makes the tools public and allows the market participants to join in the planning process. This assures that the interests and desires of all participants are considered in a coordinated manner, rather than limiting the function solely to the desires of the utility. PJM also acts as a backstop ensuring that the planning process incorporates reliability in the planning process, not just economics.

Nor did the Northeast ISOs develop their systems in secret and then try to impose them on others. To the contrary, the PJM market design is the result of several years of open participation of the market participants in creating the design of the markets. PJM

and its market participants have revised and modified the market rules on numerous occasions to make them better and to incorporate the specific desires of the market participants. Moreover, these are not unique Northeast market participants. With over 200 members, PJM's market participants are nationwide participants in the electric marketplace. There is every reason to expect these market participants to embrace a standard market design of this type elsewhere.

In short, the PJM market design simply builds on the common, everyday tools of the industry at large. Planning, scheduling, and dispatch are done every day throughout the country and the world. The only difference is that PJM's design opens up planning, scheduling, and dispatching to the market participants, rather than placing these tools inside a black box administered by the utility for itself.

That the PJM type of market design is feasible anywhere is proven by the direction of world markets. As Professor Hogan points out, it is used in existing or announced market designs in Argentina, Bolivia, Chile, Mexico, New England, New York, New Zealand, Norway, PJM, Peru, and elsewhere. As he says, "The breadth of application and success of the framework dispel the notion that the model is too complex to be implemented." Presentation at 3.

3. The Commission should resolve the question of whether market participants must submit only "covered" schedules.

Some RTOs may require all transmission customers to submit only balanced or "covered" nominations. By contrast, some operators, such as PJM, do not require balanced schedules. Under the model used by PJM, imbalances are simply deemed to be purchases from the spot market. However, an operator could require "covered" schedules even if it has an associated energy market, so this is a distinct "seams" issue. The result

of these differing approaches is a seam at any regional interface where the differing methods are used. Just as it resolved and standardized the operational balancing agreement and imbalance practices for interstate gas pipelines in Order No. 587-G, the Commission should evaluate and set the standard for this issue.

4. The Commission should resolve the policy question of what type of transmission service an RTO should offer.

Although market design is the most important issue, there are others that the Commission must address and decide before the industry can move successfully to set standards for business practices.

An important issue is determining the type of transmission service that all regions must provide. The Commission must decide whether RTOs must provide a contract path or physical path service. RTOs that continue to ignore the actual flows of energy and look only at contract path cannot effectively offer sensible redispatch options since they cannot accurately model, and therefore accurately price, the actual impact transactions have on their system. Systems that look at physical flows and price them accordingly (i.e., locational pricing) can offer effective congestion management options and do not have to rely on mechanisms like TLRs and curtailments. Without this Commission policy decision, the industry cannot adopt standard rules to implement transmission service, because the different models produce different needs and have different information requirements.

A seam exists between PJM, which allows “buy-throughs” of congestion based on energy flows, and neighboring regions in the Midwest that do not provide for this service. If on one side of a seam (PJM) a market participant can ensure the continuance of its transaction by simply stating it is willing to pay for congestion, but on the other side of

the seam (Midwest) there is no similar option (and instead TLRs are commonly used), then there cannot be common business rules that eliminate the resulting seam. There are two regimes operating, with two sets of information and scheduling needs.

The importance of defining the precise transmission service that RTOs must offer can even be seen where there are similar, but not identical, offerings in neighboring regions. The Commission currently has approved transmission service in New York that does not require the offering of firm point-to-point transmission service as a product. Rather, New York only firms service through financial rights. Yet, in PJM, on the other side of the seam, you can purchase firm transmission service. When the Commission allows one RTO not to offer firm service when its neighbor does, seamless trading becomes very difficult.

The Commission should define the transmission service that all RTOs must provide. Then the industry can adopt rational standards that will apply across seams to the required products.

5. The Commission should decide whether losses should be provided physically or financially.

Another policy decision that the Commission must make is how RTOs should deal with losses. If an RTO is allowed to require losses to be provided physically (e.g., Midwest) and a neighboring RTO allows imbalance spot markets to handle losses financially (PJM), then there will be a seam. Similarly, if the Commission allows one RTO to use average losses, while another is allowed to use incremental losses, there is an inevitable seam. The industry, no matter how much it tries, cannot come up with national standards to overcome the seam. It takes the Commission to decide the fundamental policy question. This is not to say there are not procedures that the Commission could

use to resolve these issues, but only to say the industry needs the answer from a Commission process, not a national standard setting board.

III. Once Policy Decisions Are Addressed, National Standards Setting By A New Organization May Be Appropriate For Many Seams Issues.

If the Commission resolves the key policy issues, such as those above, then a broad-based industry group, operating by consensus, could make significant contributions to the development of standard commercial practices to implement those policies. Mr. Boswell, of GISB, proposed that GISB could be modified to become “EISB,” an energy industry standards board. EISB would be divided into “quadrants,” i.e., gas-wholesale (the current GISB); gas-retail; electric-wholesale; and electric-retail. Tr. 160-61 (Boswell – GISB) Each quadrant would be formed of representatives of the indicated industry, who would develop the principles, standards, practices, and communications protocols for their industry. Id. Each quadrant would operate in the same way that GISB currently operates, with broad-based representation from each industry segment, and consensus or super-majority requirements for adoption of any standards. Id. GISB’s existing organization would bring to the table its experience on administrative and process matters. The electric industry expertise would come from the participants themselves, who would be volunteers from the companies and organizations in each segment. Id.

GISB’s “straw-man 2” proposal, described above, is appealing, and it is worthy of further discussion. In fact, GISB’s processes, as described by Mr. Boswell, appear to be very similar to the PJM stakeholder process – inclusiveness, sector representation, and action by sector consensus or super-majority. PJM can strongly attest to the effectiveness of these processes within PJM. In almost all cases, the stakeholder process has produced valuable and effective modifications and refinements to the PJM operating rules and

commercial practices. On a very few divisive or especially contentious matters, PJM has been able, as a “relief valve,” to bring issues directly to the Commission for resolution.

The EISB proposal also is very forward-looking in its allowance for “cross-quadrant standard-setting.” Tr. 161. As Mr. Boswell explained, “if one quadrant comes up with a set of standards the others think might fit, they get a say too.” Id. An EISB, containing representatives from both the gas and electric industries, would be uniquely constituted and qualified to quickly identify opportunities for, and promote, convergence between the gas and electric industries.

The Commission therefore should encourage the electric industry to explore with GISB the development of a single national group to set consensus standards for the electric and gas industries. At the technical conference, several Commissioners asked how an EISB-type organization would coordinate with a reliability organization, such as the North American Electric Reliability Council (“NERC”). Tr. 210-17. NERC’s history and processes are not as inclusive as those described by Mr. Boswell for GISB and so its role should be limited. For example, NERC currently does not permit ISOs or RTOs to have their own representation on its standing committees. This is a fatal shortcoming, given that most of the future disputes on commercial practices will be at the inter-RTO level.

The simplest way to divide responsibilities is to assign to an EISB-type group authority for all practices and rules that the Commission would require a utility to include in its filed tariff. The reliability organization would confine itself to high-level reliability standards, perhaps subject to review by EISB to the extent of their commercial implications. For example, as suggested by Mr. Boswell, NERC could be a participant

in the electric quadrant, where its concerns could be addressed by representatives of all of the industry sectors. Tr. 217.

In its GISB orders, the Commission found that because development of an integrated grid required uniform adoption of the standards, pipeline tariff provisions that were inconsistent with the standards were unjust and unreasonable.¹⁰ The Commission adopted the GISB consensus standards (through incorporation by reference) in its regulations,¹¹ and required pipelines to submit compliance filings incorporating such standards in their tariffs.¹² Similarly, the commercial rules, standards, and practices adopted by an electric industry standards board probably would be Commission-jurisdictional. As the Commission has recognized, almost all reliability rules will have a commercial consequence.¹³ Therefore, any such standard, rule, or practice that is of the nature that would require filing at FERC should be developed only through an organization that has demonstrated its ability to be inclusive and to act only by broad industry consensus, such as GISB.¹⁴

¹⁰ Standards for Business Practices of Interstate Natural Gas Pipelines, Order No. 587, FERC Stats. and Regs. ¶ 31,039, at 30,064 (1996).

¹¹ Id. at 30,062; see also 18 C.F.R. § 284.12(b), (c).

¹² Id. at 30,064.

¹³ Regional Transmission Organizations, Notice of Proposed Rulemaking, FERC Stats. and Regs. ¶ 32,541, at 33,739 (1999).

¹⁴ See Order No. 587, at 30,066 (“The Commission finds that GISB’s process was fair and that its voting procedures ensure that a broad based consensus of all industry segments support these standards.”).

CONCLUSION

Wherefore, PJM asks that the Commission consider these comments and provide additional guidance on the identified market design and policy issues, to facilitate the industry's efforts to resolve interregional inconsistencies and promote seamless, competitive wholesale markets.

Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C., this 2nd day of July, 2001.

Paul M. Flynn

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