

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

**Preventing Undue Discrimination and )  
Preference in Transmission Services )**

**Docket Nos. RM05-25-000  
RM05-17-000**

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**REPLY COMMENTS OF THE  
LARGE PUBLIC POWER COUNCIL  
IN RESPONSE TO  
NOTICE OF PROPOSED RULEMAKING**

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September 20, 2006

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**REPLY COMMENTS OF THE LARGE PUBLIC POWER COUNCIL**  
**IN RESPONSE TO NOTICE OF PROPOSED RULEMAKING**

The Large Public Power Council (“LPPC”)<sup>1</sup> hereby submits its reply comments on the Notice of Proposed Rulemaking (“NOPR”) issued by the Federal Energy Regulatory Commission (“Commission” or “FERC”) in these proceedings on May 19, 2006 and published in the Federal Register on June 6, 2006.<sup>2</sup> LPPC filed initial comments on the NOPR on August 7, 2006 (“LPPC Comments”), and initial and reply comments on the preceding Notice of Inquiry<sup>3</sup> on November 22, 2005, and January 23, 2006, respectively.

**I. EXECUTIVE SUMMARY**

**Industry Structure:** The initial comments reveal that most parties agree that the NOPR strikes a well-considered balance in its approach to open access transmission reform. LPPC strongly believes that the Commission is correct in proposing incremental reforms directed at

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<sup>1</sup> LPPC members supporting these comments are: Austin Energy, Chelan County Public Utility District No. 1, Clark Public Utilities, Colorado Springs Utilities, CPS Energy (San Antonio), IID Energy (Imperial Irrigation District), JEA (Jacksonville, FL), Long Island Power Authority, Los Angeles Department of Water and Power, Lower Colorado River Authority, MEAG Power, Memphis Light, Gas & Water Division, Nebraska Public Power District, Omaha Public Power District, Orlando Utilities Commission, Platte River Power Authority, Puerto Rico Electric Power Authority, Sacramento Municipal Utility District, Salt River Project, South Carolina Public Service Authority (Santee Cooper), Seattle City Light, Snohomish County Public Utility District No. 1, and Tacoma Public Utilities.

<sup>2</sup> *Preventing Undue Discrimination and Preference in Transmission Services, Notice of Proposed Rulemaking*, 71 FR 32,636 (June 6, 2006).

<sup>3</sup> *Preventing Undue Discrimination and Preference in Transmission Services, Notice of Inquiry*, 112 FERC ¶ 61,299 (2005) (“NOI”).

specific issues of concern, rather than a wholesale restructuring that would jeopardize the significant strides made under the Orders No. 888<sup>4</sup>/889<sup>5</sup> regime. The NOI allowed affected parties to inform the Commission on the relevant issues fully, and the proposed rule benefited substantially from the process. As do many of the commenters, LPPC supports the Commission's effort to enhance transparency of transmission planning and operations, and agrees with the Commission that additional openness and standardization of the way in which available transfer capability ("ATC") is calculated will enhance knowledge of the system and facilitate greater usage.

Those who argue that the Commission erroneously failed to address discrimination through radical restructuring along the lines of the Standard Market Design ("SMD") framework (finally terminated by the Commission in July, 2005)<sup>6</sup> ask the Commission to throw the industry back into the contentious restructuring quagmire from which it has only recently emerged. Procedurally, these proposals depart so dramatically from the NOPR that they could not lawfully be adopted in this proceeding, and would require a new NOPR for consideration. Moreover, the SMD-like proposals made by some commenters would appropriate utility generating resources in order to accomplish their objective, and thus run afoul of the jurisdictional limits imposed by the Federal Power Act ("FPA") on the Commission.

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<sup>4</sup> *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 61 FR 21540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh'g*, Order No. 888-A, 62 FR 12274 (Mar. 14, 1997), FERC Stats. & Regs. ¶ 31,048 (1997), *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000) (*TAPS v. FERC*), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002).

<sup>5</sup> *Open Access Same-Time Information System (Formerly Real-Time Information Networks) and Standards of Conduct*, Order No. 889, 61 FR 21737 (May 10, 1996), FERC Stats. & Regs. ¶ 31,035 (1996), *order on reh'g*, Order No. 889-A, FERC Stats. & Regs. ¶ 31,049 (1997), *order on reh'g*, Order No. 889-B, 81 FERC ¶ 61,253 (1997).

<sup>6</sup> *Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design*, 112 FERC ¶ 61,073 (2005) ("SMD Termination Order").

As a matter of policy, there is no record basis for believing that consumers will benefit from the implementation of an open dispatch model. While the comments on open dispatch lack much supporting detail, it seems clear that those supporting this model would like to see universal subscription to the Locational Based Marginal Cost (“LMP”) system implemented by certain Regional Transmission Organizations (“RTOs”). Yet, there is plenty of evidence for the conclusion that the reconsideration of such a system as a generic template would be a costly and disruptive exercise. To add to this picture, nearly all recent studies addressing RTO implementation support the conclusion that these institutions are costly, and provide uncertain benefits to consumers. Now is not the time to impose this framework on regions of the country and upon utilities that have decided -- generally through state and local regulatory processes supported by thorough investigation -- that the vertically integrated utility business model works best for them.

**FPA 211A – Regulation of Non-Public Utilities:** Only 9 of the 125 entities that filed initial comments specifically request full regulation of non-public utilities under an Order No. 888-style regime. More importantly, there is no record evidence upon which the Commission could base a generic finding that undue discrimination by non-public utilities in the provision of transmission service is a problem calling for generic solution. Nor does new FPA section 211A support those who argue that the Commission can or should impose the Order No 888 regime upon non-public utilities. Nonetheless, as outlined in LPPC’s initial comments, LPPC members representing nearly 90% of the non-federal municipal transmission mileage in the nation have stepped up to implement a set of “Comparability Guidelines,”<sup>7</sup> pursuant to which open access

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<sup>7</sup> See LPPC Comments at p. 16.

service will be provided under publicly available tariffs. In view of this offer, and with no historical record of undue discrimination, there is no rationale for generic Commission action.

**ATC Calculation:** Contrary to the claims of those promoting mandatory open redispatch of transmission provider generation, and the related SMD/LMP model, ATC provides a functionally useful measure of available capacity and has certain advantages over alternative models. Consistent with FPA section 217, ATC properly should be calculated in a manner which recognizes a priority for those using the transmission grid in order to meet their service obligations. Among its attributes, the ATC model enables transmission customers to buy long-term firm transmission at stable prices, fostering both reliability and commercial stability. The use of ATC is not responsible for the invocation of frequent or needless instances of Transmission Loading Relief (“TLR”) curtailments. To the contrary, in non-RTO settings, TLRs have been a limited phenomenon occurring during contingency events with modest impact on system operations. It is far outside the scope of this NOPR to challenge the existence or usefulness of the ATC calculation. FERC has made it clear that it has proposed to refine ATC calculation, and not abandon the entire concept of ATC.

**Transmission Planning:** Contrary to the claims of certain parties, there is no basis in law or policy for the Commission to direct utilities to construct facilities pursuant to regional transmission plans, or for the Commission to compel independent third party oversight of the transmission planning process. The Commission’s authority in this area is statutorily limited. With limited exceptions established under FPA section 216, (Section 1221 of the Energy Policy Act of 2005 (“EPAAct 2005”)), the Commission lacks siting authority over transmission

facilities.<sup>8</sup> This does not mean that the Commission is foreclosed from using its penalty authority in response to complaints regarding undue discrimination in the transmission planning process. Recommendations for the Commission or for third parties to assume routine decisional roles regarding transmission investment decisions will remove authority from those directly responsible to ratepayers, and may spawn ongoing litigation over transmission plans that will have the effect of thwarting, not encouraging, transmission infrastructure development.

## II. COMMENTS

### A. Summary, Scope, and Applicability of the Proposed Rule (NOPR Section IV)

#### 1. Core Elements of the Rule that Are Retained: Functional Unbundling (NOPR Section IV.B.4): The Commission Must Reject the Positions of Those Who Call for Radical Restructuring of Non-RTO Markets in the RTO/SMD Image.

Initial comments on the NOPR reveal that most of the electric industry is squarely behind the Commission's conclusion that functional (rather than structural) unbundling, as envisioned under Order No. 888, should continue to serve as the organizing principle for open access transmission service. Commenters, including LPPC, are generally supportive of the incremental changes proposed in the NOPR. The mainstream of opinion agrees with the Commission that further transparency in utility operations and planning, and clarity in the application of Commission rules (particularly with respect to the calculation of ATC) would provide substantial benefits to the industry.

Recommending a dramatic departure from this framework, consultants John Chandley and Professor William Hogan ("Chandley/Hogan") assert that ongoing discrimination can be

remedied only through “open access to the system operator’s security-constrained, economic dispatch.”<sup>9</sup> Chandley/Hogan argue that “[i]t is not true...that the source of continuing discrimination is a fundamental lack of ‘clarity and transparency’ under Order No. 888.”<sup>10</sup> Chandley/Hogan contend, instead, that service “comparability” calls for the Commission to recognize that generation dispatch is routinely used by utilities in order to provide service over congested transmission facilities (on an out-of-merit basis, when justified), and that the failure to offer this service to open access customers is inherently discriminatory.<sup>11</sup> Chandley/Hogan further argue that Commission-sanctioned RTO market organization accurately reflects appropriate utility organization, and that the Commission must organize non-RTO markets identically.<sup>12</sup> While Chandley/Hogan do not refer to their proposal as an LMP system, it seems quite clear that this is what they have in mind: the out-of-merit generation dispatch, with pricing for customers taking advantage of this service on a basis which reflects the marginal cost of generation used to perform the dispatch. Other writings of the authors indicate that they believe this system appropriately calls for bid-based pricing in the establishment of the marginal cost of generation in order to accomplish redispatch.

Summarizing their recommendations in terms that make it unmistakably clear that their proposals in this docket cannot be distinguished from the now-repudiated SMD framework, Chandley/Hogan have this to say:

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<sup>9</sup> Chandley/Hogan Comments of August 2, 2006 (“Chandley/Hogan Comments”) at p. 26. The Chandley/Hogan Comments are endorsed, in whole or in part, by the American Wind Energy Association (“American Wind”), PJM Interconnection, L.L.C., (“PJM”), the ISO/RTO Council, the Midwest Independent System Operator (“MISO”), San Diego Gas & Electric Co. (“SDG&E”), and NRG Energy, Inc. (“NRG”).

<sup>10</sup> *Id.* at p. 8.

<sup>11</sup> *Id.* at pp. 17–18; 23–26.

<sup>12</sup> *Id.* at pp. 18–20.

Given this history, and the repeated experience, the evidence is overwhelming. The time is long overdue for the Commission to acknowledge this fact and to reform Order 888 to require all transmission providers to offer open, non-discriminatory access to the provider's security-constrained, economic dispatch, with prices for dispatch and redispatch defined by marginal costs.<sup>13</sup>

The prospect of radical industry restructuring of non-RTO utility operations called for in this proposal would wreak havoc on the industry at a time when it has just begun to recover from the impact of several years of restructuring uncertainty and political backlash caused by very similar proposals. The wisdom of the Commission's NOPR proposal lies in its measured and pragmatic approach to improvements in industry structure. The experience of the past several years makes it plain that radical restructuring of the electric industry is a costly and controversial exercise, with highly uncertain results and tremendous economic and reliability risks. In the context of this history, the Commission's decision to allow industry models to develop, regionally and voluntarily, and to seek incremental improvement through increasing transparency and clarity is eminently sensible.

Despite claims to the contrary,<sup>14</sup> the Chandley/Hogan recommendations are practically indistinguishable from those advanced (by Chandley and Hogan themselves) under the banner of SMD in FERC Docket No. RM01-12. While the Chandley/Hogan piece lacks the detail of earlier recommendations, at its core, the essence of the Chandley/Hogan model remains the same. As Professor Hogan previously stated in 2002:

There are many details of the required standard market design. However, the centerpiece is the organization of system operations including energy balancing, short-term reliability and transmission congestion management through a coordinated spot market using

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<sup>13</sup> *Id.* at p. 51.

<sup>14</sup> *Id.* at p. 37.

bid-based, security-constrained economic dispatch with locational prices.<sup>15</sup>

Since these comments fundamentally track those filed in this docket, it seems quite clear that the Chandley/Hogan effort seeks to reanimate the SMD docket.<sup>16</sup>

Although Chandley/Hogan stop short of arguing that all utilities must be RTO members,<sup>17</sup> their supporters are not so reticent. PJM asserts that the Commission “articulates no reasoned basis for back-tracking from Order No. 2000’s<sup>18</sup> findings that functional unbundling is inadequate or its conclusion that achieving competitive markets requires independent operational control of transmission.” Asserting that “the NOPR’s reach is too narrow,” PJM argues that structural separation of merchant and transmission operations is required.<sup>19</sup> American Wind argues similarly that some form of structural reorganization, such as RTO participation, should be required.<sup>20</sup>

Moreover, it seems clear that despite Hogan/Candley's assertion that they are not recommending mandatory RTO participation,<sup>21</sup> this piece of the SMD framework is an integral aspect of the market structure the Professor would impose on the nation. Again, in the SMD docket, Professor Hogan commented:

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<sup>15</sup> *Electricity Market Design and Structure: Avoiding the Separation Fallacy*; Comments of William Hogan in Docket No. RM01-12 at p. 1 (March 12, 2002) (“March 2002 SMD Comments”).

<sup>16</sup> The Commission terminated the SMD docket by order dated July 19, 2005. *See* SMD Termination Order.

<sup>17</sup> Indeed, Chandley/Hogan recognize that such an argument would be “beyond the scope and purpose of this NOPR.” Chandley/Hogan Comments at p. 20.

<sup>18</sup> *Regional Transmission Organizations*, Order No. 2000, 65 FR 809 (Jan. 6, 2000), FERC Stats. & Regs. ¶ 31,089 (1999), *order on reh’g*, Order No. 2000-A, 65 FR 12088 (Mar. 8, 2000), FERC Stats. & Regs. ¶ 31,092 (2000), *aff’d sub nom. Public Utility District No. 1 of Snohomish County, Washington v. FERC*, 272 F.3d 607 (D.C. Cir. 2001).

<sup>19</sup> PJM Initial Comments of August 7, 2006 (“PJM Comments”) at pp. 13–23.

<sup>20</sup> American Wind Initial Comments of August 7, 2006 (“AWEA Comments”) at p. 11.

<sup>21</sup> Chandley/Hogan Comments at p. 4.

The Poolco model of an ISO providing a bid-based economic dispatch, charging locational spot prices and administering a system of transmission congestion contracts is the *only* internally consistent and workable approach that has been described for operating an efficient, non-discriminatory competitive electricity market in the presence of complex network interaction.<sup>22</sup>

In a subsequent filing in the SMD docket, Chandley and Hogan had this to say:

Because there is *no means to efficiently price redispatch absent the SMD*, systems operators will not willingly incur the costs of redispatch to support transmission service requests. The inability to offer an efficiently priced redispatch can result in the exclusion of transactions from the grid, even if the transactions would have been economically justified if the customer were required to pay the marginal costs of any needed redispatch. Order No. 888 can thus leave the grid significantly underutilized....The important advance of the SMD over Order No. 888 is that the Independent Transmission Provider will arrange redispatch – through bid-based security-constrained economic dispatch – to accommodate every request for transmission service and then price and charge for that redispatch using LMP.<sup>23</sup>

Clearly the comments of those supporting Chandley/Hogan and recommending open access to generation service and RTO implementation are indeed taking a second bite at the SMD apple and making a collateral attack on the Commission's decision to terminate the SMD docket.

LPPC's further objections to the Chandley/Hogan recommendations, and those of their supporters, are these:

- Proposals for the implementation of the SMD/LMP model and for mandatory RTO membership are outside the scope of this proceeding.

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<sup>22</sup> March 2002 SMD Comments at p. 6, quoting Chandley and Hogan, *Independent Transmission Companies in a Regional Transmission Organization*, Center for Business and Government, Harvard University at pp. 36–37 (January 8, 2002) (emphasis added).

<sup>23</sup> Initial Comments of John D. Chandley and William W. Hogan on the Standard Market Design, Docket No. RM01-12, filed November 11, 2002 at p. 43 (emphasis added).

- The SMD/LMP model wrongfully appropriates generation assets built by vertically integrated utilities in order to serve their native load, in conflict with limitations on the Commission’s jurisdiction under the Federal Power Act.
- The SMD/LMP model, and mandatory RTO participation, conflicts with the operation of vertically integrated utilities in regions of the country that have determined that the efficiencies of the vertically integrated utility model should be preserved.
- Transparency and further clarity in the calculation of ATC is a legitimate means of addressing discrimination in the use of the transmission grid. Mandatory redispatch is *not* the only means of preventing discrimination and the subjective nature of redispatch decisions, even when made by RTOs, cannot be ignored.
- Centralized dispatch and the imposition of an RTO framework has not proven to be a panacea for improving transmission investment.
- This proceeding is the wrong forum for determining whether there are seams issues between RTO and non-RTO regions. It is hardly clear that non-RTO utilities impose uncompensated costs on RTOs; on the other hand, there *is* evidence that RTOs impose costs on their non-RTO neighbors.

**a. Recommendations for Radical Industry Restructuring are Beyond the Scope of this Proceeding.**

Whatever their merit as a matter of public policy, proposals for radical restructuring of non-RTO regions of the electric industry cannot be implemented in this docket. Section 553(b)(3) of the Administrative Procedure Act (“APA”) specifies that notice of a proposed rule must contain “either the terms or substance of the proposed rule or a description of the subjects

of the subjects and issues involved.”<sup>24</sup> In *American Federation of Labor and Congress of Industrial Organizations, et al., v. Donovan*, 757 F.2d 330, 338 (D.C. Cir. 1985) (“*AFL-CIO v. Donovan*”), the court made it clear that while a final rule need not be identical to the proposed rule it must, at least, be a “logical outgrowth” of the proposed rule in order to conform to the notice requirement of the APA. Other than that both proposals address the structure of the electric industry, there is no reasonable relationship between the Commission’s proposal in the NOPR and proposals by Chandley/Hogan for the implementation of the SMD/LMP framework and mandatory RTO participation. Indeed, as noted above, the Commission specifically terminated the SMD docket that addressed the type of restructuring advocated by Chandley/Hogan. The Commission would be hard pressed to maintain that the very restructuring program that was discontinued by the SMD Termination Order is now an outgrowth of the proposals in this NOPR. As the court made plain in *AFL-CIO v. Donovan*, “[I]f the final rule deviates too sharply from the proposal, affected parties will be deprived of notice and an opportunity to respond to the proposal.”<sup>25</sup>

Nor can it be argued that the debate taking place in these comments supplies the required notice under the APA. Again, as the court held in *AFL-CIO v. Donovan*, the agency “must itself provide notice of a regulatory proposal. Having failed to do so, it cannot bootstrap from a comment.”<sup>26</sup> Accordingly, if the Commission is interested in seriously entertaining the Chandley/Hogan proposals, or any further recommendations for mandatory RTO participation, it must establish a new rulemaking in order to do so.

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<sup>24</sup> 5 U.S.C. section 553(b)(3).

<sup>25</sup> *AFL-CIO v. Donovan* at 338.

<sup>26</sup> *Id.* at p. 340.

**b. The SMD/LMP model wrongfully appropriates generation assets built by vertically integrated utilities in order to serve their native load, in conflict with limitations on the Commission’s jurisdiction.**

Chandley/Hogan’s position that discrimination in the provision of transmission service can only be remedied through mandatory open dispatch of utility generation in a way that would attempt to replicate the use of generation in vertically integrated operations is objectionable on equitable grounds and unlawful. The very centerpiece of the Chandley/Hogan SMD/LMP framework is the appropriation of generation built by a vertically integrated utility or other transmission owner to meet its service obligations, including native load, in order to effectuate third-party transmission transactions. While the SMD/LMP model provides compensation for the use of these facilities, the program depends on the premise that a utility’s generation is to be made available to third parties (whether through a bid-based system or on a marginal cost basis). Assuming “open” dispatch is mandatory, native load will compete with other users in order to secure adequate supply.<sup>27</sup> By its very nature, the SMD/LMP framework appropriates generation assets paid for by utility ratepayers and built to serve native load markets. In so doing, the SMD/LMP framework prevents utilities from exercising a priority for using generation built in order to serve retail native load (or other service obligation) markets on a cost of service basis. Instead, with the implementation of the SMD/LMP structure, utilities would be required to depend on an uncertain market in order to meet service obligations including retail needs.

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<sup>27</sup> Chandley/Hogan Comments at pp. 35-36. The Chandley/Hogan piece lacks much of the detail of their earlier submissions. Yet, it is plain that the Chandley/Hogan SMD/LMP framework is very unlike the limited redispatch protocol now included in section 13.5 of the open access transmission tariff (“OATT”), since that provision is limited to redispatch in circumstances in which the transmission provider has determined that the service will not degrade or impair service to native load customers, network customers or other transmission customers taking point-to-point service. *See* NOPR at P 307. By contrast, the SMD/LMP model assumes no such limitation, and, indeed, assumes that generation is always available to perform a redispatch function.

Fairness notwithstanding, it is beyond doubt that the mandatory imposition of the SMD/LMP model is beyond the Commission's jurisdiction. While Chandley/Hogan argue that implementation of the SMD/LMP model alone will assure that service for competitive transactions is "comparable" to the manner in which vertically integrated utilities provide service to their sales markets, their argument begs the critical question -- just what is being compared. To go back to first principles, in Order No. 888, the Commission required comparability between (1) the use of transmission facilities by utilities in the provision of bundled sales service with (2) the use of transmission service by third parties. Of course, in Order No. 888, the Commission went no further than to find that a public utility's transmission wires must be made available on an open access basis. The courts agreed, affirming in *Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000).

Stepping well beyond that framework, Chandley/Hogan ask the Commission to find that service comparability now requires the Commission to require comparability in the manner in which utilities use their generation resources in order to serve native load with third party transmission transactions. Yet, the Federal Power Act makes it quite clear that the Commission's jurisdiction does not extend to a utility's generating facilities.

Section 201(b)(1) of the FPA provides, in pertinent part:

The Commission shall have jurisdiction over all facilities for . . . transmission or sale of electric energy, but shall not have jurisdiction, except as specifically provided in this subchapter and subchapter III of this chapter, over facilities used for the generation of electric energy or over facilities used in local distribution or only for the transmission of electric energy in intrastate commerce, or over facilities for the transmission of electric energy consumed wholly by the transmitter.<sup>28</sup>

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<sup>28</sup> 16 U.S.C. section 824(b)(1) (emphasis added).

Chandley/Hogan fail even to address this obvious limitation on the Commission's authority, other than to state their conclusion that "the dispatch is the essential transmission service."<sup>29</sup> In fact, the use of generation is not a transmission service. PJM does only slightly better, attempting to come to grips with the FPA by defining it away, asserting that transmission can be construed to include generation. According to PJM: "As a legal matter, dispatch should be regarded as a critical element of transmission service necessary in order to access the transmission grid in the same manner as the Commission regards interconnection service."<sup>30</sup> PJM cites the Commission's decision in Order No. 2003 defining generation interconnection service as a form of transmission service.<sup>31</sup>

The flaw in PJM's reasoning is self-evident. FPA section 201(b) makes it absolutely clear that transmission and generation are distinct functions, and that the Commission is forbidden from regulating the use of the latter. With that statutory distinction in mind, it cannot reasonably be argued that the form of generation regulation contemplated by SMD/LMP is somehow incidental to the regulation of transmission. The SMD/LMP framework calls for the required use of generation in order to serve customers, along with price regulation (whether marginal cost or as bid) for service rendered by generation facilities. Whether strategically placed generation can be used by vertically integrated utilities to serve load or whether

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<sup>29</sup> Chandley/Hogan Comments at p. 38.

<sup>30</sup> PJM Comments at p. 19, fn. 11.

<sup>31</sup> *Citing Standardization of Generator Interconnection Agreement and Procedures*, Order No. 2003 at P 9, 68 Fed. Reg. 49,845 (August 19, 2003), FERC Stats. and Regs., Regulations Preambles 2001-2005 ¶ 31,146 (2003), *order on reh'g*, Order No. 2003-A at P 113, 69 Fed. Reg. 15,932 (March 26, 2004), FERC Stats. and Regs., Regulations Preambles 2001-2005 ¶ 31,160 (2004), *order on reh'g*, Order No. 2003-B, 70 Fed. Reg. 265 (January 4, 2005), FERC Stats. and Regs., Regulations Preambles 2001-2005 ¶ 31,171 (2004), *order on reh'g*, Order No. 2003-C, 70 Fed. Reg. 37,661 (June 30, 2005), FERC Stats. and Regs., Regulations Preambles 2001-2005 ¶ 31,190 (2005); *see also Notice Clarifying Compliance Procedures*, 106 FERC ¶ 61,009 (2004) and *Tennessee Power Company v. FERC*, 90 FERC ¶ 61,238; *reh'g dismissed*, 91 FERC ¶ 61,271 (2000).

transmission facilities deliver energy from remote sources to serve that load is entirely beside the point: electric generation is not transmission, and the FPA purposely recognizes the difference.<sup>32</sup>

Nor does PJM's reference to the Commission's decision to consider generation interconnection a form of transmission service help its cause. The interconnection of a generator to the transmission grid plainly involves the use, and often the improvement, of transmission facilities. Under Order No. 2003, there was no attempt to expand regulation to generating facilities, only to transmission facilities and costs.

In closely analogous circumstances, the courts have rejected the Commission's contention that regulation may be extended to matters specifically excluded from regulation under statute because the subject of the regulation is the functional equivalent of a jurisdictional service. Thus, *e.g.*, the court in *Northwest Pipeline Corp. v. FERC*, 905 F.2d 1403, 1410-11 (10th Cir. 1990) rejected the Commission's exercise of jurisdiction over natural gas gathering facilities, despite the claim that because Northwest Pipeline's primary business function is the interstate transportation of gas, its gathering facilities must be subject to the Commission's jurisdiction.<sup>33</sup> Similarly, in *Detroit Edison Co. v. FERC*, 334 F.3d 48, 54-55 (D.C. Cir. 2003), the court rejected the claim that the Commission's regulation extends to local distribution facilities expressly exempt from Commission jurisdiction under section 201(b) of the FPA. The court rejected the argument that the Commission had the authority to extend its jurisdiction to distribution facilities used exclusively to provide unbundled service to retail customers. That

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<sup>32</sup> See, *e.g.*, *Jersey Central Power & Light Co. v FPC*, 319 U.S. 61, 72 (1943).

<sup>33</sup> The Commission included natural gas storage facilities within the ambit of its jurisdiction over interstate natural gas transportation, under the Natural Gas Act ("NGA"). See *Colorado Interstate Gas Co.*, 41 FERC ¶ 61,179 at 61,460 (1987). Yet, the NGA does not have a provision expressly exempting storage from FERC regulation, as is the case with electric generation. Moreover, it has never been suggested that the Commission should exercise jurisdiction over natural gas production (following its deregulation), even in situations where it may also be used as a surrogate for long-distance transportation, as is arguably the case with production located in market regions.

extension was thought by the Commission to be consistent with open access policy, but was nevertheless struck down by the court in view of the express language of the statute.

The extent to which the Chandley/Hogan proposal is at odds with the legitimate scope of the Commission's jurisdiction is underscored by their frustration with the conception of Commission jurisdiction embodied in the Public Utility Regulatory Policies Act of 1978 ("PURPA").<sup>34</sup> In Chandley/Hogan's view, Congress started down the open access path on the wrong foot in authorizing the Commission to compel "wheeling" under section 211 of the FPA. That very concept, according to Chandley/Hogan misconceives the true nature of utility operations: it refers only to the use of transmission wires on a contract path basis and ignores the open dispatch/security-constrained/SMD/LMP framework that Chandley/Hogan wish to visit on the non-RTO regions of the nation. But the views of those authors regarding what Congress should or should not have done is an entirely meaningless exercise. What is important -- and what Chandley/Hogan rail against -- is that Congress gave the Commission jurisdiction over transmission used in interstate commerce, and did not grant similar jurisdiction over generation. Chandley/Hogan may feel free to quarrel with Congress, but the Commission does not have that luxury.

Finally, the Chandley/Hogan discourse comparing transmission service under a non-RTO Order No. 888 tariff with service in RTO markets which have adopted the LMP framework is pointless.<sup>35</sup> Addressing how "comparable service" might be defined, Chandley/Hogan comment that "[a]nother path the Commission might take would be to ask how transmission service is provided to third parties by traditional utilities, and compare that to how transmission service is

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<sup>34</sup> Chandley/Hogan Comments at p. 40.

<sup>35</sup> *See id.* at pp. 18–21, 30–32.

provided to the same parties by today's RTOs...."<sup>36</sup> Without a doubt, as Chandley/Hogan point out,<sup>37</sup> the LMP framework administered by RTOs under Day 2 markets differs from the Order No. 888 framework administered by utilities outside of RTOs. Yet, it cannot be overemphasized that the RTO framework is a voluntary one within which utilities are free to offer certain services the Commission may not compel. Accordingly, the fact that the SMD/LMP framework has been adopted by certain RTOs has no bearing on the question whether the Commission has the authority to compel adherence to that framework outside the RTO context.

**c. The SMD/LMP model, and mandatory RTO participation, conflicts with the operation of vertically integrated utilities in regions of the country that have determined that the efficiencies of the vertically integrated utility model should be preserved.**

The past several years have been witness to a heated and politically charged battle over the question whether to impose a single industry structure on public utilities around the nation.<sup>38</sup> The NOPR wisely steers clear of this debate, allowing RTO markets to develop according to their own lights, and non-RTO utilities to continue to operate under the Order No. 888 framework. With the passage of time, there may well be more definitive evidence of the relative costs and benefits of various business models and some consensus. But no such consensus has yet emerged, and at this juncture it can be said definitively that there is no substantial record in this proceeding upon which to conclude that the RTO SMD/LMP model offers clear net benefits that would justify its uniform imposition. Furthermore, there is some evidence that wholesale prices and retail rates in RTO areas compare *unfavorably* with those of non-RTO areas.

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<sup>36</sup> *Id.* at p. 18–19.

<sup>37</sup> *Id.* at p. 19.

<sup>38</sup> The July 19, 2004 letter from a group of 20 Senators to former Chairman Wood lodged in Docket No. RM01-12 decrying the SMD NOPR reflected the depth of unhappiness with the Commission's proposal to impose a uniform business model upon the industry.

As noted above, Chandley/Hogan have maintained that they are not necessarily recommending the implementation of an RTO in order to administer their SMD/LMP dispatch model. Even if one were to take that disclaimer at face value, it is nevertheless clear that the Chandley/Hogan dispatch model would reconfigure the business model of a vertically integrated utility to the extent that the current dedication of an integrated utility's generation to first meet its native load service obligation would be undermined, as the generation function would be reallocated in order to grant third parties equal access to generation needed to accomplish redispatch.

As was pointed out in a recent analysis published by the Cato Institute,<sup>39</sup> there has been surprisingly little debate among regulators at the federal level over the economies associated with the operation of vertically integrated utilities in the electric utility industry. The Cato Institute further reveals that there is strong evidence in the research literature that there are efficiencies and savings resulting from integrated operations and planning of transmission, distribution, and generation which have been overlooked in the rush to develop competitive models. Studies of the benefits of vertical integration surveyed by the Institute show efficiency savings ranging up to nearly 14%.<sup>40</sup> While this evidence cannot be taken as conclusive, it underscores that it would be a mistake for the Commission to impose a model that risks sacrificing those efficiencies.

Of course, if RTOs or RTO-type systems are mandated, there are substantial additional costs to consider. Analyses of the costs and benefits of RTO/ISO formation performed over the past several years highlight the significant ongoing debate as to the cost effectiveness of the

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<sup>39</sup> Robert Michaels, *Vertical Integration and the Restructuring of the U.S. Electric Industry*, Cato Institute Policy Analysis No. 572, (July 13, 2006) (available at <http://www.cato.org/pubs/pas/pa572.pdf>).

<sup>40</sup> *Id.* at Appendix.

RTO/ISO business model. For example, in response to the Grid West proposal in the Northwest, Henwood Energy Services conducted a study that concluded there would be costs in excess of the benefits. The study found:

an annual net cost of approximately \$122 million due to RTO formation [an average of \$200 million in annual costs less \$78 million in annual benefits]. Henwood believes that this \$78 million in benefits is generous given the assumption we made that control areas are not making economic short term reserve associated short term bi-lateral contracts today.<sup>41</sup>

The Grid West Study further cautioned that “individually every single RTO displays a substantial upward trend in costs” and that “[h]istory has shown that, no matter how limited in scope and budget the initial design of the RTO may be, the trend is for costs to escalate well beyond initial estimates.”<sup>42</sup>

In response to the proposal to establish RTOs in the Southeast, Charles River Associates conducted a study concluding that “there is considerable uncertainty as to whether RTO/SMD would provide net benefits to the southeast.”<sup>43</sup> Under various scenarios, including Day 1 and Day 2 RTO markets, the study concluded that, generally, the “GridSouth area does not appear to have positive net benefits,” the “SeTrans area generally has positive net benefits,” and “GridFlorida is close to breaking even in most scenarios, but has negative net benefits in the reduced merchant scenarios in particular.”<sup>44</sup> The Southeast Study estimated that the costs of starting up a Day 2 market exceeded the costs of starting up a Day 1 market by \$60 million and

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<sup>41</sup> *Final Report, Study of Costs, Benefits and Alternatives to Grid West*, by Henwood Energy Services, Inc., dated October 15, 2004 (“Grid West Study”) at p. ES-6 (available at <http://www.ksg.harvard.edu/hepg/Papers/Henwood.grid.west.1004.pdf>).

<sup>42</sup> *Id.* at pp. 5-1, 5-7.

<sup>43</sup> *The Benefits and Costs of Regional Transmission Organizations and Standard Market Design in the Southeast*, by Charles River Associates, dated November 6, 2002 (“Southeast Study”) at 95 (available at [http://www.crai.com/pubs/pub\\_2901.pdf](http://www.crai.com/pubs/pub_2901.pdf)).

<sup>44</sup> *Id.* at p. 95.

that annual costs of running Day 2 markets exceeded the annual costs of running Day 1 markets by \$30 million.<sup>45</sup> Further, the costs of RTO/SMD tended to be front-end loaded – which meant that any benefits were only realized several years after implementation.<sup>46</sup>

Similarly, in support of its decision to terminate the GridFlorida Transco RTO project,<sup>47</sup> the FPUC cited a report prepared by ICF International concluding that:

the prospect of a basic Day-1 RTO operation as proposed are “bleak,” with the Peninsula Florida costs exceeding the Peninsula Florida benefits by over \$700 million over the three year operating period. Under a more advanced Day-2 RTO operation, ICF concludes that the total project benefits are a negative \$285 million in Peninsular Florida over the ten year operating period. However, ICF points out there is the potential by year 13 for GridFlorida’s operations benefits to equal its costs.

FERC accepted the GridFlorida notice of termination in a June 19, 2006 order in Docket No. RT01-67-000.

Adding to this unhappy picture, even those touting the efficiency gains of restructured markets have sharply curtailed their projections for efficiency gains in recent years.<sup>48</sup>

In light of this ongoing scholarship and debate over the costs and benefits of an RTO/ISO restructured market, it would be a substantial misstep for FERC now to choose either to compel participation in the SMD/LMP market design or to compel RTO membership. Obviously, the

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<sup>45</sup> *Id.* at p. 24.

<sup>46</sup> *See id.* at p. 74.

<sup>47</sup> Notice of Termination of GridFlorida Transco Project, Docket No. RT01-67-000, dated June 12, 2006, citing the May 9, 2006 order of the Florida Public Service Commission (“FPUC”) at pp. 3-4 (ICF’s December 12, 2005 report is available at [http://www.icfi.com/Markets/Energy/doc\\_files/gridflorida-rto-report.pdf](http://www.icfi.com/Markets/Energy/doc_files/gridflorida-rto-report.pdf)).

<sup>48</sup> *See* “All Pain, No Gain,” pointing to a dramatic decline in even hoped-for efficiency gains from RTO markets over the years, with 1995 estimates of short-term price reductions of 40% declining sharply to 2002 estimates of short-term price reductions of 3-5%. *See All Pain, No Gain, Restructuring and Deregulation in the Interstate Electricity Market*, Dr. Mark Cooper, dated September 2002 at 5-6, 22 (available at <http://www.consumerfed.org/pdfs/allpain.pdf#search=%22All%20Pain%2C%20No%20Gain%20Mark%20Cooper%22>).

record in this proceeding lacks any substantial evidence demonstrating net benefits associated with these proposals.

**d. Additional transparency and clarity in the calculation of ATC is a legitimate means of addressing discrimination in the use of the transmission grid.**

Chandley/Hogan are wrong in maintaining, as they do throughout their submission in this case, that (1) the calculation of ATC is a virtually worthless exercise, with little bearing on the amount of capacity actually available to the grid, and (2) that mandatory redispatch is the *only* means to prevent discrimination in the provision of transmission service.<sup>49</sup> The principal advantage of ATC is the certainty that it provides for available capacity. The ATC/contract path paradigm facilitates long-term bilateral contracting, which provides: (1) long-term revenue streams that power producers need to obtain financing for infrastructure development; and (2) buyers with delivered power cost certainty. While real-time operating conditions can change the exact amount of transmission that will actually become available, this does not invalidate the long-term bilateral contracting benefits of the ATC/contract path paradigm.

This is not to say that improvements in the manner in which ATC is calculated are not called for. LPPC members' experience is that the quality of ATC calculations varies substantially around the nation, and LPPC vigorously supports the Commission's effort to maximize system usage and root out discrimination through rules now under development that would require better transparency and clarity in ATC methodology.

Nonetheless, Chandley/Hogan's conclusion that ATC standardization is a waste of time, is contradicted by NERC's view that while ATC values can and should be improved, this is a

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<sup>49</sup> See Chandley/Hogan Comments at pp. 4, 9, 11.

worthwhile exercise and one that is consistent with the reliable operation of the grid. Among other things, in this very docket, NERC has this to say:

NERC, in its August 15 comments on the Commission's Notice of Inquiry, "Information Requirements for Available Transfer Capability," agreed that there is a need to continue the enhancement of the calculation of ATC and ATC-related values to support the wholesale power market while maintaining adequate reliability for all users. NERC also indicated its support of the recommendations of its Long-Term AFC/ATC Task Force (LTAF), the Commission and the industry to add increased standardization and consistency to the current NERC reliability standards on ATC and ATC-related values.<sup>50</sup>

NERC believes that through commonality of calculation techniques, assumptions, communication, the exchange of data among the various ATC calculators, and the documentation of methods and assumptions, the calculation of ATC values can be made more transparent, consistent, and useful to the marketplace without negatively impacting the reliability of the bulk power system.<sup>51</sup>

Furthermore, in recounting the discourse it has had with the industry in connection with the development of ATC standards, NERC comments that while the industry has wrestled with a variety of technical issues associated with ATC calculations, the validity of the exercise has not been called into question.<sup>52</sup> Accordingly, it seems clear that the industry does not share Chandley/Hogan's view that it is engaged in a worthless exercise when fine-tuning the approach to ATC calculations.

Chandley/Hogan are also wrong in maintaining<sup>53</sup> that ATC cannot be calculated independent from actual use of the grid. In fact, ATC is a reflection of intended use of the grid,

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<sup>50</sup> NERC Initial Comments on August 7, 2006 ("NERC Comments") at p. 2.

<sup>51</sup> *Id.* at pp. 8–9.

<sup>52</sup> *Id.* at p. 4.

<sup>53</sup> Chandley/Hogan Comments at p. 9

and while some variations in actual capacity will occur in real-time, an advance snapshot is critical in determining available capacity, particularly for longer-term firm transactions. Real-time deviations from scheduled use of the system have certainly not been shown to be a persistent or prevalent problem. While the contract path method of operating the transmission grid does not always precisely reflect the way that power actually flows, in LPPC's experience, the use of ATC calculations to determine available capacity has facilitated the purchase and sale of large amounts of transmission capacity on Open Access Same-time Information System ("OASIS") sites.<sup>54</sup>

Nor are Chandley/Hogan correct that the use of ATC is responsible for the invocation of frequent or needless instances of TLR curtailments. To the contrary, in non-RTO settings, TLRs have been a limited phenomenon with modest impact on system operations. In fact, according to NERC data, over 80% of the TLRs occurring between 2003 and 2006 were called not on non-RTO systems, but in RTO/ISO areas, particularly MISO and PJM.<sup>55</sup>

Equally important, ATC is a concept that goes hand-in-hand with the reservation of capacity by utilities in order to meet their service obligations. As discussed in LPPC's initial comments, and as the Commission has recognized, new section 217 of the FPA entitles load-serving entities, which include distribution utilities, electric utilities, and power marketing administrations, to use the transmission capacity they own or to which they have rights under contract to meet their service obligations (*i.e.*, native load). The ability so to reserve firm capacity in order to meet existing commitments is a feature of ATC methodology, although

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<sup>54</sup> In fact, more than 22,000 Transmission Service Requests (TSRs) per month (26,376 in June; 26,573 in July; and 22,254 in August) were processed through the Western Interconnect's wesTTrans OASIS during the past three summer months of 2006

<sup>55</sup> According to the NERC TLR data ([http://www.nerc.com/pub/sys/all\\_updl/oc/scs/logs/trends.htm](http://www.nerc.com/pub/sys/all_updl/oc/scs/logs/trends.htm) at the "Data" tab), over 80% of TLRs occurring from 2003-2006 were initiated by RTO/ISO reliability coordinators.

Chandley/Hogan deny that it is a legitimate exercise. Instead, in the Chandley/Hogan world, all uses of the system have equal priority, on the ground that all use eventually serves someone's native load.<sup>56</sup> As Chandley/Hogan put it: "Instead of asking 'what's left (using ATC calculations) for third parties, assuming no further dispatch is permitted,' the Commission should require all transmission providers to ask the same questions it would ask if the provider were serving its own native loads."<sup>57</sup> Put another way, all capacity uses have equal priority, and are put on the margin in instances of congestion. Whatever the merit of the economic theory behind the Chandley/Hogan view, it is fundamentally at odds with the requirements of FPA section 217, and thus cannot be implemented in this proceeding or elsewhere.

Further in response to the argument made by Chandley/Hogan that grid loop flows render ATC an inadequate means of capturing system usage, it bears pointing out that loop flow can indeed be managed without the overlay of a complicated command and control LMP redispatch framework. In the Western Interconnect, loop flows are largely prevented by use of direct-current technology and phase shifters, so that loop flow constraints between control areas only affect a small amount of transmission usage. A path with persistent and significant loop flow is designated by the WECC as a "Qualified Path" and is handled through the WECC's Unscheduled Flow Mitigation procedure.<sup>58</sup>

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<sup>56</sup> This view is also expressed by: Constellation Energy Group ("Constellation"); Electricity Consumers Resource Council, American Iron and Steel Institute, and American Forest and Paper Assoc. ("ELCON"); Energy Power Supply Association ("EPSA"). See Constellation Initial Comments of August 7, 2006 ("Constellation Comments") at pp. 62-63; ELCON Initial Comments of August 7, 2006 ("ELCON Comments") at p. 3; EPSA Initial Comments of August 4, 2006 ("EPSA Comments") at pp. 9-10.

<sup>57</sup> Chandley/Hogan Comments at p. 29.

<sup>58</sup> The WECC's Unscheduled Flow Procedure is an interconnection-wide procedure intended to mitigate excessive loop flow on seven specific "Qualified Paths" in the WECC. These seven Qualified Paths have a history of being adversely impacted by unscheduled flow. The procedure is essentially a three phase approach. First, schedules are reduced on a Qualified Path by the parties scheduling on the path to accommodate some portion of the unscheduled flow (initially 5%). Second, phase shifting transformers located throughout WECC are operated in a coordinated

Finally, it is emphasized that generation may indeed be used (and is commonly used) in order to circumnavigate congested transmission pathways, without recourse to the LMP/redispach model. It is done simply by virtue of the fact that outside organized LMP markets parties routinely engage in bilateral energy sales in order to avoid the use of fully subscribed lines. These transactions are a function of good economics, they require minimal regulatory intervention, and they make eminent sense.

**e. Centralized dispatch and the imposition of an RTO framework has not proven to be a panacea for improving transmission investment.**

It bears pointing out that while LMP was initially promoted (by Dr. Hogan himself) as a means of facilitating transmission investment, the track record for investment in SMD/LMP markets appears to demonstrate that LMP markets have had just the opposite effect. Accordingly, one of LMP's initial selling points has now been thoroughly undermined through practical experience. To the extent that one of the Commission's goals in the NOPR has been the promotion of transmission investment, it clearly must look elsewhere.

The testimony submitted before FERC by Dr. Hogan in support of the redesign of the New York Independent System Operator ("NYISO") market is representative of the claims that were once made for the SMD/LMP model. There, Dr. Hogan claimed that with LMP,

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manner to relieve the unscheduled flow. Third, if additional relief is required, transactions which are *not* scheduled on the Qualified Path but are contributing to flow on the path are curtailed. The WECC Unscheduled Flow Reduction Procedure is available at <http://www.caiso.com/docs/2004/09/27/200409271346577748.pdf#search=%22Western%20Electricity%20Unscheduled%20Flow%20Reduction%22>.

transmission investment would essentially take care of itself, once the LMP price signals were understood.<sup>59</sup> As Dr. Hogan explained:

Under the New York Proposal, necessary investments in transmission facilities need not be determined exclusively by an administrative process. Rather, the need for transmission upgrades would be driven more by market forces, relying as much as possible on the incentives of avoiding congestion payments derived from differences in LBMPs and by the costs of upgrades. The role of planning and regulation would be narrower, addressing the unavoidable interactions in the transmission grid. To a greater extent than occurs today, investment decisions would be made at the initiative and with the agreement of those required to bear the cost within such an environment. Differences in locational marginal prices and the desire to avoid congestion charges would provide economic incentives for expansion of the transmission grid ...<sup>60</sup>

In Hogan's view, LMP price signals would themselves engender investment, with little need for further intervention.<sup>61</sup> While Hogan predicted that NYISO would need to take some role in regional transmission expansion, he testified that this role would entail "evaluating the impacts of proposed transmission expansions" and "coordinating" and not making a "central decision."<sup>62</sup> In support of Hogan's conception, NYISO's sponsoring entities commented that as a result of LMP price signals "[i]n general, transmission expansion under the proposed structure will take place at the initiative and expense of market participants."<sup>63</sup>

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<sup>59</sup> See Report on the Proposal to Restructure the New York Electricity Market prepared by William W. Hogan, appended to the January 31, 1997 filing of Central Hudson Gas & Electric Co., *et al.*, in Docket No. ER97-1523-000 at pp. 43, 75-80 ("Hogan NYISO Testimony").

<sup>60</sup> Hogan NYISO Testimony at pp. 75-76.

<sup>61</sup> *Id.* at p. 77.

<sup>62</sup> *Id.* at p. 79.

<sup>63</sup> Transmittal Letter of January 31, 1997 of Central Hudson Gas & Electric Co., *et al.*, in Docket No. ER97-1523-000 at p. 24.

Notwithstanding these lofty claims, the NOPR notes that transmission investment has been inadequate over the last decade and that “there has been a significant decrease in transmission capacity relative to load in every NERC region.”<sup>64</sup> Moreover, the Commission’s 2004 State of the Market Report provides a bleak snapshot of the state of RTO investment in new transmission projects.<sup>65</sup> RTOs with LMP price signals failed to provide significant additions to their transmission system. Neither the Independent System Operator of New England (“ISO-NE”) nor NYISO added a single mile of high-voltage transmission in 2004.<sup>66</sup> In PJM, only 6 miles of high-voltage transmission were added in 2004.<sup>67</sup> While it could be argued that a lack of investment in transmission meant that the price signal to build simply was not there, the Department of Energy (“DOE”) Study on National Electric Transmission Congestion of August 2006 reports otherwise.<sup>68</sup> The DOE Study reveals that a major “Critical Congestion Area” extends through all three of these LMP markets of 2004 – ISO-NE, NYISO, and PJM.<sup>69</sup>

**f. This proceeding is the wrong forum for determining whether there are seams issues between RTO and non-RTO regions.**

PJM requests that FERC act in this proceeding to remedy the alleged “discrimination and impediments to competition that exist along” seams between RTO and non-RTO markets.<sup>70</sup> PJM argues that non-RTO “free-riders” obtain benefits from RTO markets without paying the full

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<sup>64</sup> NOPR at P 31-32.

<sup>65</sup> 2004 FERC State of the Markets Report at pp. 74, 80, 88, 97, 102, 112, 125, 135 (available at <http://www.ferc.gov/EventCalendar/Files/20050615093455-06-15-05-som2004.pdf>).

<sup>66</sup> *Id.* at pp. 88, 97 (Eleven miles of lower voltage transmission were added to ISO-NE (115 kV)).

<sup>67</sup> *Id.* at p. 112.

<sup>68</sup> DOE Study on National Electric Transmission Congestion of August 2006 (“DOE Study”) (available at [http://www.oe.energy.gov/DocumentsandMedia/Congestion\\_Study\\_2006\\_web.pdf](http://www.oe.energy.gov/DocumentsandMedia/Congestion_Study_2006_web.pdf)).

<sup>69</sup> *Id.* at pp. viii, 41-44.

<sup>70</sup> PJM Comments at pp. 31-32.

costs they impose on RTO markets.<sup>71</sup> To remedy PJM's alleged problem with free-riders, PJM asks that FERC require RTO border entities to open their redispatch to RTOs, and submit compliance filings with FERC addressing the issue of free-riding. *Id.* PJM also asks for FERC to clarify that an RTO is not required to treat non-members the same as RTO members. *Id.*

**i. The free-rider issue is outside the scope of this proceeding.**

Whatever the merits of PJM's free-rider issue, it is clearly outside the scope of the proceeding. Certainly, the issue was not raised in the NOPR, with the result that the parties are not on notice that the free-rider issue is in play in this docket.<sup>72</sup> Moreover, the issue has already been included within the scope of FERC Docket No. AD06-9-000, in which the Commission is actively seeking to gather information on RTO border issues. In the technical conference scheduled in that case, the Commission has stated:

participants are asked to identify discrete concerns and contrasting views, establish which specific market services, reliability functions, and other features of RTO/ISO markets provide non-members with benefits for which they may not bear an appropriate share of the respective costs, or otherwise should not be entitled to, and propose solutions to identified problems.<sup>73</sup>

PJM, of course, has the opportunity to address its free-rider issues in that proceeding.

Substantively, what PJM has to say about this issue is far from established, and ignores substantial evidence of the flip-side of this issue: costs that RTOs foist upon their neighbors. With respect to administrative costs upon which it is said non-RTO members capitalize, it bears pointing out that non-RTO members certainly do not escape charges levied by the CAISO. In

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<sup>71</sup> *Id.* at pp. 31-38.

<sup>72</sup> See 5 U.S.C. section 553(b)(3); *AFL-CIO v. Donovan*.

<sup>73</sup> See Notice of Technical Conference of June 8, 2006 in Docket No. AD06-9-000, as well as the June 21, 2006 Notice Postponing Technical Conference.

order to use CAISO transmission service, non-members must pay a wheeling access charge (“WAC”).<sup>74</sup> This WAC spreads a share of the CAISO’s transmission costs to members and non-members, based on usage. The grid management charge (“GMC”) is an additional CAISO usage charge that the California Independent System Operator Corporation (“CAISO”) imposes on non-members. Under the GMC, non-members pay a share of the CAISO’s operating costs, which include the CAISO’s costs for reliability services, congestion management, settlements, metering, and client relations.<sup>75</sup> Obviously, there is no “free” ride for non-CAISO members. Other RTOs are, of course, free to propose similar charges.

Nor is there a convincing case that redispatch in non-RTO markets is needed to resolve cross-the-border loop flows. PJM asks FERC to take action regarding loop flows that it alleges: (1) are being caused by border entities; and (2) benefit border entities.<sup>76</sup> PJM asks that FERC address this problem in this proceeding by requiring border entities to provide open dispatch. *Id.* Even if loop flows are a significant operational burden to PJM (a conclusion which PJM does not support with substantial evidence), FERC does not need to mandate open dispatch to resolve loop flows. Incidental loop flows in the WECC and ERCOT are currently being addressed without need for such open dispatch mandate.<sup>77</sup>

There is, moreover, the flip side of this issue which PJM does not address, and which will be fully aired in Docket No. AD06-9-000 – the extent to which RTOs spread costs to their neighbors. Border entities may be forced to adjust the way they operate their own control areas,

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<sup>74</sup> See CAISO Tariff Appendix A, “Wheeling Access Charge.”

<sup>75</sup> See CAISO Tariff Appendix A, “Grid Management Charge.”

<sup>76</sup> PJM Comments at pp. 33-34.

<sup>77</sup> See the discussion of the WECC’s Unscheduled Flow Procedure, above.

or change their business models to accommodate their RTO neighbors, with resulting costs. For example, physical rights entities that border financial rights RTOs have experienced significant difficulty in maintaining preexisting transmission service and in obtaining long-term transmission service through these neighboring RTOs. While FERC is seeking to address this problem in the Final Rule on Long Term Firm Transmission Rights in Organized Markets in Docket No. RM06-8-000, FERC acknowledges that these long-term firm rights are not currently available in any RTO utilizing LMP.<sup>78</sup> Further, the complexity of a neighboring RTO congestion management system can force delays in obtaining transmission service and can bar access to power supplies. Moreover, there is a considerable internal administrative expense for RTO border entities that must do business with neighboring RTO markets.

LPPC raises these issues, not to seek a definitive resolution here, but rather to point out that there are contrasting perspectives on the “free rider” subject. This proceeding is simply not the place to resolve the issue.

**ii. PJM’s argument that a TLR is an inefficient and discriminatory form of redispatch is wrong.**

PJM argues that non-RTO border entities discriminate against RTOs when they curtail RTO member exports from the non-member control area by use of TLR orders.<sup>79</sup> PJM states that FERC should end this discrimination by requiring border entities to open their redispatch to RTO members as part of the reciprocity requirement. *Id.*

First, TLRs are not designed as a substitute for redispatch. As noted above, the incidence of TLRs is infrequent, and not at all limited to non-RTO regions. TLRs are uncommon because

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<sup>78</sup> *Final Rule on Long Term Firm Transmission Rights in Organized Markets*, 116 FERC ¶ 61,077 (2006) at P 30.

<sup>79</sup> *Id.* at pp. 32.

physical rights markets do not offer firm transmission unless they believe that it will not be curtailed. TLRs occur when there are unanticipated events preventing scheduled transmission from occurring, such as a double contingency outage. By contrast, redispatch is a frequent occurrence in an RTO's daily operations. Indeed, redispatch is an integral component of the RTO transmission model.

Second, TLRs, if they occur, affect all firm schedules equally. They do not discriminate amongst members and non-members. NERC's TLR procedures make no distinction between the transaction schedules or the native loads of RTO members and non-members. Nor do NERC's TLR procedures make a distinction between the transaction schedules or the native loads of affiliates and non-affiliates.

Third, RTOs do not eliminate TLRs. NERC's website indicates that TLRs are not confined to non-RTO areas. In fact, NERC data indicates that the vast majority of TLRs have been occurring in RTOs – particularly MISO and PJM.<sup>80</sup>

Fourth, PJM's call for market-based congestion management administered by a "disinterested dispatch authority"<sup>81</sup> comes with a hefty administrative price tag. It is hardly clear that an RTO's administration of congestion management is a more cost-effective way to resolve congestion than is the occasional use of TLRs. There is, as PJM admits, considerable operator discretion involved in redispatch<sup>82</sup> and an operator using mandatory redispatch may schedule closer to the boundaries of system capacity than an operator under a physical rights model. This may maximize system utilization, but it increases the uncertainty of congestion

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<sup>80</sup> According to the NERC TLR data ([ftp://www.nerc.com/pub/sys/all\\_updl/oc/scs/logs/trends.htm](ftp://www.nerc.com/pub/sys/all_updl/oc/scs/logs/trends.htm) at the "Data" tab), over 80% of TLRs occurring from 2003-2006 were initiated by RTO/ISO reliability coordinators.

<sup>81</sup> PJM Comments at p. 37.

<sup>82</sup> *Id.* at p. 28.

costs for firm uses. That is the tradeoff many transmission *customers* are unwilling to make and it has nothing to do with an integrated transmission provider trying to gain an advantage. Further, to properly compare the costs of congestion management using TLRs, the marginally priced payments made to generators in an RTO must also be considered as costs. Additionally, when generation bids are not competitive, the RTO model may add even further costs.

Fifth, the WECC (with the exception of Bonneville Power Administration), which is largely a non-RTO, physical rights region, does not use TLRs. WECC protocols provide for alternative methods of addressing both unscheduled loop flows and force majeure events. TLRs do not even necessarily exist in certain major non-RTO regions.

Finally, if the Commission allows RTOs to dictate service offerings to bordering entities, then the RTOs' borders will have effectively been expanded to encompass the "first-tier" border entities. The logic of that expansion would further support an RTO in alleging that second-tier entities (*i.e.*, those bordering first tier entities) are likewise guilty of discrimination, and so on. In this regard, PJM suggests that energy schedules, which have their source or sink in Florida, are to blame for problems in PJM.<sup>83</sup> Like PJM, those LPPC members not in RTOs have loop flow and congestion to deal with – and LPPC members manage these issues by adopting protocols, by constructing new transmission facilities, and, if other options fail, using TLRs (in the Eastern Interconnection). PJM's insistence on restructuring its neighbors and, potentially, second tier entities is utterly unreasonable.

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<sup>83</sup> *Id.* at p. 34.

**2. Applicability of the Proposed Rule - Non-Public Utility Transmission Providers/Reciprocity (NOPR Section IV.C.2)**

**a. There is no record evidence of NJE undue discrimination that would justify FERC reversing its NOPR decision to act on a case-by-case basis under FPA section 211A.**

While several parties<sup>84</sup> ask FERC to take generic action compelling non-jurisdictional entities (“NJE”) to provide open access service under Order No. 888, as was the case in comments on the NOI, no accompanying evidence is offered that non-public utilities have generally failed to offer open access service upon request. Instead, what is offered are the generalizations that an Order No. 888 requirement would promote transparency and simplify, clarify, and streamline transmission service requests.<sup>85</sup> Several entities provide unsupported assertions that grid reliability would be enhanced by taking generic action against NJEs.<sup>86</sup> Additional vague claims are made that failing to take generic action against NJEs will: (1) add undue burdens on FERC in managing case-by-case complaints against NJEs; (2) fail to respect Congress’s intent in adopting FPA section 211A; (3) allow continued RTO/ISO free-riding; (4) leave perceptions of discrimination; and (5) materially compromise FERC’s ability to police *jurisdictional* tariffs.<sup>87</sup>

The common thread underlying these comments is that they fail to provide any specific examples of undue discrimination by NJEs, let alone a pattern of such undue discrimination or

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<sup>84</sup> These commenters include: the California Public Utilities Commission (“CPUC”), Calpine Corporation (“Calpine”), Edison Electric Institute (“EEI”), MidAmerican Energy Company/PacifiCorp (“MEC”), National Grid USA (“National Grid”), SDG&E, and Xcel Energy Services Inc. (“Xcel”).

<sup>85</sup> EEI Initial Comments of August 7, 2006 (“EEI Comments”) at pp. 23-24; MEC Initial Comments of August 7, 2006 (“MEC Comments”) at pp. 7-8; Xcel Initial Comments of August 7, 2006 (“Xcel Comments”) at p. 8.

<sup>86</sup> Calpine Initial Comments of August 7, 2006 (“Calpine Comments”) at p. 5; CPUC Initial Comments of August 3, 2006 (“CPUC Comments”) at pp. 29-31; National Grid Initial Comments of August 7, 2006 (“National Grid Comments”) at pp. 41-42; MEC Comments at p. 8.

<sup>87</sup> Calpine Comments at p. 7; CPUC Comments at pp. 29, 31; Xcel Comments at p. 10; SDG&E Initial Comments of August 7, 2006 (“SDG&E Comments”) at pp. 9-10.

lack of access. The sweeping, policy-driven generalizations made by these entities are unsupported by affidavits, citations to FERC findings of NJE undue discrimination, or even citations to complaints of NJE undue discrimination (whether successful or not). Nor could such a record be compiled. As LPPC pointed out in its initial comments, the instances of complaints seeking transmission access from non-public utilities under pre-existing FPA section 211 are exceedingly rare.<sup>88</sup> Likewise, there is no evidence of an investor-owned utility refusing to provide service to an unregulated transmitting utility on the ground that reciprocal service was not provided.<sup>89</sup>

Any action taken by the Commission must, of course, be supported by substantial evidence.<sup>90</sup> By the same token, generic action must be supported by evidence of a general problem to which a rule is addressed. While the courts have permitted the Commission to act in a generic setting to remedy what are seen to be pervasive abuses, precedent is clear that it is not reasonable to adopt an “industry-wide solution for a problem that exists in only isolated pockets.”<sup>91</sup> Consistent with these principles, the factual underpinning for the action undertaken in Order No. 888 was the Commission’s general finding of a need to address a “fundamental generic problem in the electric industry”<sup>92</sup> It would be unreasonable to interpret section 211A to

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<sup>88</sup> Since 1992, the Commission has in only four cases directed that transmission service be provided by unregulated transmitting utilities other than the Tennessee Valley Authority (“TVA”). Reported cases involving TVA include: *East Kentucky Power Cooperative*, 112 FERC ¶ 61,160 (2005); *Cinergy Services*, 81 FERC ¶ 61,243 (1997), *final order issued*, 95 FERC ¶ 61,007 (2001); *AES Power*, 69 FERC ¶ 61,345 (1994), *final order issued*, 74 FERC ¶ 61,220 (1996). Two of the four situations would not be addressed even under new section 211A, as the cases appear to involve small NJEs that would be exempt under section 211A(c)(1). *Pinnacle West Capital Corporation*, 100 FERC ¶ 61,146 (2002) and *Citizens Utility Company*, 75 FERC ¶ 61,240 (1996).

<sup>89</sup> See LPPC Comments at p. 9.

<sup>90</sup> See, e.g., *Pacific Gas and Elec. Co. v. FERC*, 373 F.3d 1315, 1319 (D.C. Cir. 2004).

<sup>91</sup> *Associated Gas Distributors v. FERC*, 824 F.2d 981, 1019 (D.C. Cir. 1987); see also *Williams Natural Gas Co. v. FERC*, 943 F.2d 1320 (D.C. Cir. 1991).

<sup>92</sup> See, e.g., *Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff’d sub nom.*, *New York v. FERC*, 535 U.S. 1 (2002); Order No. 888 at 31,679; see also NOI at PP 3-4.

allow the Commission to compel open access to the transmission facilities of unregulated utilities for less compelling a reason.<sup>93</sup>

Consistent with case law, FERC made it clear in the NOI that any action undertaken would require specific evidence, rather than mere generalizations based on policy. Emphasizing its intention to “avoid the more polarizing elements of this debate,” the Commission stated its intention to:

pursue instead a pragmatic approach to reforming Order No. 888 that focuses on the specific problems that continue to exist and targeted remedies to address them. To that end, we encourage the parties to identify *with specificity* any alleged defects in Order No. 888 and to recommend reforms that are *appropriately targeted* to remedying those defects. Sweeping generalizations regarding undue discrimination (or the lack thereof) are not encouraged.<sup>94</sup>

With no identified pattern of NJE undue discrimination offered in response to the NOPR, there is simply no basis for generic Commission action.

Further supporting the Commission’s approach, FPA section 211A plainly allows the Commission to act within its discretion to address any situation where it finds that a particular unregulated transmitting utility is not providing adequate access to its transmission facilities. Moreover, FPA section 211A contains no standard specifying circumstances in which the Commission *must* act. FERC’s decision in the NOPR to decline to act generically falls well within its discretion. As the court held in *EMR Network v. FCC*, 391 F.3d 269, 272 (D.C. Cir. 2004), deference to an agency’s decision refusing to initiate a rulemaking is “at the high end of

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<sup>93</sup>*United States, ex rel. D.S. Findley v. FPC – Boron Employees’ Club*, 105 F.3d 675, 681 (D.C. Cir. 1997), *cert. denied*, 522 U.S. 865 (1997) (explaining that “[i]n determining the meaning of the statute, we look not only to the particular statutory language, but to the design of the statute as a whole and to its object and policy.”); *Blacklight Power, Inc. v. Rogan*, 295 F.3d 1269, 1273 (Fed. Cir. 2002) (same).

<sup>94</sup> NOI at P 7 (emphasis in original).

the range,” and overturned only in the “rarest and most compelling of circumstances.”<sup>95</sup> Because the record in this proceeding does not include specific, substantial evidence of a pattern of NJE undue discrimination and only contains generalized policy justifications for generic action against NJEs, FERC’s NOPR proposal to act on a case-by-case basis is well-supported.

Of specific note, SDG&E’s argument that failure to take generic action against NJEs will compromise FERC’s ability to police jurisdictional tariffs is simply nonsensical.<sup>96</sup> SDG&E makes a vague, unspecified reference to “scores of allegations [that] were raised during the California energy crisis” regarding NJEs exploiting “loopholes in the CAISO’s jurisdictional tariff.”<sup>97</sup> Yet, SDG&E fails to draw any logical linkage between such ostensible manipulation and the fact that NJEs in California have not generally adopted the *pro forma* OATT.

Nor is there any basis for the incendiary claim that the Commission’s decision not to impose a generic OATT upon non-public utilities threatens system reliability.<sup>98</sup> As the Commission and the parties are well-aware, new section 215 of the FPA and the Electric Reliability Organization’s (“ERO”) associated reliability standards apply equally to non-public and public utilities. LPPC members have never claimed otherwise, and the idea that the applicability of regulation under the Order No. 888 OATT is an integral aspect of the reliability regime is completely unsupported.

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<sup>95</sup> *Citing, American Horse Protection Ass’n, Inc. v. Lyng*, 812 F.2d 1, 4 (D.C. Cir. 1987); *WWHT, Inc. v. FCC*, 656 F.2d 807, 818 (D.C. Cir. 1981).

<sup>96</sup> SDG&E Comments at pp. 9-10.

<sup>97</sup> *Id.*

<sup>98</sup> Calpine Comments at p. 5.

**b. Contrary to the assertions of the CPUC and TAPS, it is clear that Congress did not intend that NJEs should be regulated like public utilities or adopt the *pro forma* OATT.**

**i. CPUC**

The CPUC argues that in light of the language that Congress adopted in FPA section 211A, “the Commission should respect the intent of Congress by actively exploring a set of mandatory actions that it may impose on non-jurisdictional entities.”<sup>99</sup> Yet, the implication that Congress intended that NJEs should be forced to adopt the *pro forma* OATT is simply not so.<sup>100</sup> First, the language of the statute expressly leaves it within FERC’s discretion to decide whether or not to act under FPA section 211A, stating that FERC “may” take action against NJEs by “rule or order.” Second, the action FERC may take against NJEs is expressly limited to requiring rates, terms, and conditions that are “comparable” to those the NJE provides “itself.” This comparability requirement falls well short of the CPUC’s position that non-public utilities adopt the terms of the *pro forma* OATT.

Furthermore, as explored at length in LPPC’s earlier comments,<sup>101</sup> the legislative history of section 211A clearly shows that Congress did not intend to provide the Commission with the authority to impose the full OATT open access regime applicable to jurisdictional utilities upon NJEs. Prior iterations of the legislation predating EAct 2005 included provisions that:

- Would have provided FERC with full jurisdiction over unregulated utilities under FPA sections 205 and 206;<sup>102</sup>

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<sup>99</sup> CPUC Comments at pp. 29-30; *see also* Calpine Comments at p. 3.

<sup>100</sup> Additionally, the CPUC’s apparent suggestion that FERC should require NJEs to join RTOs/ISOs to prevent the “balkanization of the grid” (CPUC Comments at p. 30) clearly runs afoul of FPA section 211A(j), which holds that FERC may not require NJEs to transfer control or operation of their transmission facilities to an RTO/ISO.

<sup>101</sup> *See* LPPC Comments at pp. 11–15; Comments of LPPC in Response to NOI of November 22, 2005 at pp. 33-37.

- Would have defined unregulated utilities as “public utilities” for most substantive purposes under the FPA,<sup>103</sup> and
- Would have provided FERC with the authority to require unregulated utilities to provide service on the same terms and conditions as is required of regulated utilities.<sup>104</sup>

This decade-long legislative history of FPA section 211A and its antecedents makes it clear that Congress considered successively narrower jurisdictional provisions applicable to unregulated transmitting utilities, and that the provision that was ultimately adopted was the narrowest of any considered. Had Congress intended to authorize the Commission (let alone direct it) to regulate non-public utilities as it does jurisdictional entities, it would have said so.

## ii. TAPS

The Transmission Access Policy Study Group (“TAPS”) is wrong in claiming that the comparability provision in section 211A can only be satisfied through implementation of a *pro forma* OATT. According to TAPS, upon complaint, the OATT embodies the “only terms and conditions that meet the ‘no undue discrimination’ standard ... [that] can pass muster under Section 211A.”<sup>105</sup> The complaint process under section 211A that TAPS envisions is one in which the NJE must either show that its safe harbor tariff actually “meets the requirements of Order 888 and the final rule in this proceeding” or, failing to make such showing, the NJE must then adopt the OATT. But to the contrary, FPA section 211A(b) requires only that NJEs offer transmission service on rates, terms, and conditions that are comparable to those that the NJE

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<sup>102</sup> See Comprehensive Electricity Competition Act, S. 1047, 106th Cong. § 301 (1999) (introduced by Sen. Frank Murkowski and Sen. Jeff Bingaman, by request); Comprehensive Electricity Competition Act, H.R. 1828, 106th Cong. § 301 (1999) (introduced by Rep. Tom Bliley and Rep. John Dingell, by request); Electric Power Market Competition and Reliability Act, S. 2098, 106<sup>th</sup> Congress (2000).

<sup>103</sup> Electric Competition and Reliability Act, H.R. 2944, 106<sup>th</sup> Congress (1999).

<sup>104</sup> Energy Policy Act of 2002, S. 1766, 107th Cong., § 206 (2001) (introduced by Sen. Tom Daschle).

<sup>105</sup> TAPS Initial Comments of August 7, 2006 (“TAPS Comments”) at p. 15.

provides to itself. As explained above, there is no support for the view that Congress intended to grant FERC the authority to regulate NJEs as it does jurisdictional utilities. While earlier versions of section 211A would have granted FERC such authority, Congress chose instead to authorize the Commission (when justified) only to compel the provision of “comparable service.”

**c. FERC appropriately retains reciprocity as the default standard for NJE service.**

As explained in LPPC’s initial comments, LPPC members have committed to provide open access pursuant to publicly available tariffs under a set of “Comparability Guidelines,” pursuant to which a range of services will be offered that are fundamentally similar to the *pro forma* OATT.<sup>106</sup> Nevertheless, LPPC sees no reason for the Commission to abandon the reciprocity standard as the default standard for the provision of transmission service by non-public utilities.

EEI argues that the service obligations of non-public utilities should now be extended to common-carrier status, on the ground that the limitation contemplated by the reciprocity condition was initially animated by the concern that open access service might threaten an NJE’s tax status, and that this concern has now been resolved by final Internal Revenue Service (“IRS”) regulations resolving that transmission service does not violate private use restrictions on the use of tax exempt funding.<sup>107</sup>

Yet, while the Commission in the Order No. 888 series was indeed cognizant of IRS code concerns, the rationale for the reciprocity rule lay much more broadly in the Commission’s basic conception of fairness. A fair reading of Order No. 888 is that what animated the reciprocity

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<sup>106</sup> See LPPC Comments at pp. 15-17.

<sup>107</sup> EEI Comments at p. 27, *citing* Order No. 888-A at 30,287.

requirement was the Commission’s interest in addressing the “fundamental fairness” of requiring an entity to make its facilities available to another entity that was not under a similar, reciprocal obligation.<sup>108</sup> LPPC continues to support that basic fairness concept. And while LPPC members are willing to move further to provide open access to all eligible customers that is comparable to what LPPC members provide themselves, the essential *quid pro quo* underlying the reciprocity rule continues to call for no more than the mandatory provision by an NJE of service that they provide themselves (that is surplus to their service obligations) to utilities from which they seek service themselves.

In response to EEI’s view that the reciprocity obligation must be extended to all members of an RTO to which a jurisdictional utility from which service is requested might belong,<sup>109</sup> LPPC notes that such a requirement substantially exceeds the Commission’s “fundamental fairness” concept. Similarly untethered is EEI’s claim that service must be offered to all independent generators, regardless of their transmission ownership.<sup>110</sup> In both cases, LPPC reminds the Commission that section 211 will always serve as a backstop for complaints on a case-by-case basis. Moreover, LPPC again reiterates that comparable, surplus service under NJE-specific tariffs pursuant to LPPC’s proposed Comparability Guidelines would be provided on an open access, common-carrier basis to all eligible customers, including independent generators.

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<sup>108</sup> See Order No. 888-B at 62,078; Order No. 888-A at 30,287.

<sup>109</sup> EEI Comments at p. 26.

<sup>110</sup> *Id.*

**d. There is no need for the incremental NJE compliance requirements that EEI proposes.**

In apparent recognition of the Commission’s intention in the NOPR not to extend full regulation under the Order No. 888 OATT to NJEs, EEI offers a series of recommendations ostensibly designed to “strengthen” NJE reciprocity requirements. Accordingly, EEI asks FERC to: (1) mandate that certain NJE information is posted on FERC’s website; (2) require NJEs to comply with the rules regarding ATC calculation standardization; and (3) actively scrutinize NJE participation in regional transmission planning processes.<sup>111</sup> Finally, EEI argues that the Commission should specify that NJEs are required to provide all service they are capable of providing, not only service comparable to the service they provide themselves. For reasons argued below, these requirements are wholly unnecessary, run afoul of the express direction of Congress in EAct 2005, and would be of little or no value to open access customers, or to the industry generally.

**i. Posting NJE data on FERC’s website**

EEI proposes that FERC increase NJE “transparency and accountability” by including a list of all NJEs with safe harbor tariffs on its website and requiring NJEs to make informational filings indicating: (1) whether they have a reciprocity tariff; (2) whether they have an OASIS; (3) whether they have adopted standards of conduct; (4) whether they have posted business practices; (5) their contact for regional planning; and (6) their ATC methodology.<sup>112</sup>

EEI’s proposed transparency and accountability requirements are unnecessary and duplicative of information that is already generally available and accessible on NJE websites.

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<sup>111</sup> *Id.* at pp. 24, 30

<sup>112</sup> *Id.* at pp. 30-32.

The purpose of transparency should be to allow transmission customers access to the information they need to purchase transmission. Market participants seeking to purchase transmission service do not normally seek information relevant to available transmission service on FERC's website.<sup>113</sup> Instead, they directly access the OASIS websites of the utilities from whom it makes sense to purchase transmission. Under Order No. 889, a key element of reciprocity is the requirement that an NJE that takes OATT service must, in return, post its unused transmission capacity on an OASIS, unless it obtains a waiver.<sup>114</sup> As a result the majority of non-regulated transmitting utilities currently offer unused transmission capacity on OASIS. These NJE OASIS websites already contain the information that is necessary in order obtain transparent information on NJE transmission – the same information EEI wants posted on FERC's website and included in NJE compliance filings.<sup>115</sup> FERC should not adopt the unnecessary and duplicative transparency requirements EEI requests.

## **ii. NJE compliance with ATC standardization**

EEI asks FERC to require that “non-public utility transmission providers [ ] adhere to the proposals for consistent methodologies and practices in connection with ATC calculations.”<sup>116</sup> EEI's request is unnecessary and, again, redundant. As FERC recognizes in the NOPR, NERC and NAESB are currently drafting standardized guidelines for calculating ATC.<sup>117</sup> As LPPC noted in its initial comments, its members are actively engaged in this ATC guideline drafting process at NERC and NAESB and recognize that members will be bound by these standards to

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<sup>113</sup> Public utilities are not currently required to post this information on FERC's website, and, instead, post such information on their OASISes.

<sup>114</sup> Order No. 889 at 31,587.

<sup>115</sup> *See* 18 C.F.R. Part 37 (OASIS requirements).

<sup>116</sup> EEI Comments at p. 24.

<sup>117</sup> NOPR at P 149.

the extent they are incorporated in NERC reliability standards applicable to both public and non-public utilities.<sup>118</sup> These NERC standards, when final, will be filed with FERC, become part of the ERO's mandatory reliability standards and will be fully applicable to otherwise non-jurisdictional entities. As a result, the ATC standards will be applicable to, and enforceable upon, all transmission owners, whether or not the transmission owner has adopted the OATT. EEI's recommendation is superfluous.

### **iii. NJE participation in transmission planning processes**

In light of FERC's express expectation that NJEs participate in open, transparent, and coordinated transmission planning processes, EEI asks FERC to "actively monitor and enforce" the compliance of municipal, cooperative, and other public power entities.<sup>119</sup> There is no need for the Commission to take special action in monitoring NJE compliance with the requirement to participate in regional transmission planning. LPPC members have committed to participate in regional transmission planning processes in LPPC's initial comments.<sup>120</sup> LPPC noted that this commitment was consistent with ongoing planning processes in which LPPC members were already actively engaged.

### **iv. Comparability and capability**

In its proposed revisions to section 6 of the *pro forma* OATT (Reciprocity), EEI asks the Commission to approve language that would obligate a non-public utility to provide "any transmission service that it is capable of providing to [an eligible customer] including the

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<sup>118</sup> LPPC Comments at p. 19.

<sup>119</sup> NOPR at P 214; EEI Comments at p. 24.

<sup>120</sup> LPPC Comments at pp. 26-27. LPPC members own close to 90% of the non-federal municipally-owned circuit line miles of 138 kV and above located in the Eastern and Western Interconnections. *See id.* at p. 16.

Transmission Provider on comparable terms and conditions...”<sup>121</sup> A requirement to provide all services a non-public utility is capable of providing goes far beyond the express intent of Congress and is unreasonably open-ended. Instead, consistent with LPPC’s initial comments in this matter, and in recognition of the express language of FPA section 211A, LPPC suggests that the obligation stated in the opening section 6 of the *pro forma* OATT be amended as follows:

A Transmission Customer receiving transmission service under this Tariff agrees to provide transmission service to the Transmission Provider that is comparable to the service which the Transmission Customer provides to itself when such service is surplus to the service obligations of the Transmission Customer.

**B. Proposed Modification of the OATT (NOPR SECTION V)**

**1. Transmission Planning - Coordinated, Open, and Transparent Planning (NOPR Section V.B)**

As noted in LPPC’s initial comments, LPPC members are committed to an open, participatory regional planning process, consistent with the NOPR, and Attachment K of the proposed OATT. The Commission’s indication in the NOPR<sup>122</sup> that it expects that non-public utilities will participate in the planning processes the Commission envisions is consistent with LPPC members’ plans, and indeed with much current practice. There is, accordingly, no call for the Commission to take further action with respect to non-public utility participation in the planning process that might test the limits of its jurisdiction under FPA section 211A.<sup>123</sup>

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<sup>121</sup> EEI Comments at p. 28.

<sup>122</sup> NOPR at P 214.

<sup>123</sup> It is a long leap from the authority granted the Commission in new FPA section 211A to require non-public utilities to provide comparable transmission service to an order which would require them to participate in regional planning processes. LPPC’s voluntary commitment to such participation averts the need to address that issue. LPPC notes that Southern California Edison (“SCE”) appears to call for such compulsion, anomalously citing EPAct 2005 section 1231(e), governing exemptions from new FPA section 211A. SCE Initial Comments of August 7, 2006 at p. 4. The citation is inapposite.

LPPC does take issue with those arguing that the Commission should exercise ongoing oversight of the planning process, including authority over transmission construction pursuant to regional plans. Nor does LPPC see any justification for the establishment of independent transmission coordinators.

**a. The decision to build transmission facilities and to carry out transmission plans must rest with transmission providers.**

Constellation argues that “(iii) the transmission provider must make periodic reports to the Commission describing progress of regional planning; and (iv) the transmission provider must commit to construct system improvements that are approved in the transmission planning process.”<sup>124</sup> NRG argues that the Commission must modify the OATT to state, “Transmission owners must submit a plan to construct on a timely basis all network upgrades required to ensure serve [*sic*] to current and planned network loads over the next five years under postcontingency (N-1) conditions.”<sup>125</sup> TDU Systems argue that “existing provisions of the OATT regarding transmission providers’ responsibility for expanding their systems should be strengthened into unmistakable, enforceable obligations.”<sup>126</sup> Similarly, TAPS argues that FERC “should strengthen the connection between planning and construction by clarifying that TPs will be obligated to build facilities identified in the regional plan.”<sup>127</sup>

While LPPC is squarely behind the Commission’s effort to achieve a more open and participatory planning process, LPPC believes it would be unwise, and probably unlawful, for the Commission to assume general jurisdiction over transmission construction. Particularly in

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<sup>124</sup> Constellation Comments at pp. 8-9.

<sup>125</sup> NRG Comments at p. 14.

<sup>126</sup> TDU Systems Initial Comments of August 7, 2006 at p. 30.

<sup>127</sup> TAPS Comments at p. 43.

non-RTO areas where vertically integrated transmission providers have load serving obligations, the decision of whether or not transmission should be built must be left to state authorities. With a Commission leap into this area, one can well envision endless litigation over transmission plans, costs and construction orders, the unintended consequence of which may very well be to undermine, not promote, transmission investment.

Moreover, it is hardly clear that the Commission has the statutory authority to compel construction pursuant to regional transmission plans. Obviously, the Commission lacks general siting authority, an area reserved to state regulation and laws governing state eminent domain. EAct 2005's grant to the Commission of limited siting authority for transmission corridors designated by the DOE to be national interest electric transmission corridors underscores the conclusion that general authority is lacking in this area.<sup>128</sup> Similarly, new section 215 of the FPA specifically provides that FERC may not "order the construction of additional generation or transmission capacity," even for reliability reasons.<sup>129</sup> The Commission has itself recognized that "State regulators, not this Commission, have siting authority for electric generation and transmission facilities."<sup>130</sup>

In the case of non-public utilities, the case for mandatory Commission authority is even more attenuated. FPA section 211A makes no mention of siting authority over non-public utilities. And while the statute authorizes the Commission to compel the provision of

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<sup>128</sup> See FPA section 216.

<sup>129</sup> FPA section 215(i)(2).

<sup>130</sup> See *Removing Obstacles to Increased Electric Generation and Natural Gas Supply in the Western United States*, 94 FERC ¶ 61,272 at 61,967 (2001); Energy Policy Act of 1992 section 731 ("Nothing in this title or in any amendment made by this title shall be construed as affecting or intending to affect, or in any way to interfere with, the authority of any State or local government relating to environmental protection or the siting of facilities.").

comparable transmission service, transmission construction pursuant to FERC-approved regional transmission plans is a long way from the limited statutory authority granted in section 211A.

This is not to say that the Commission lacks all authority when presented with evidence of undue discrimination through the planning process. One can imagine legitimate Commission action, including the imposition of penalty authority in the presence of persuasive claims of discrimination. Yet, such instances are far better left to the specific circumstances, in which utility behavior may be closely examined.

Nor is there justification for the proposed requirement to have transmission providers file their plans for the purpose of ongoing review. Transmission plans are based on assumptions that change constantly. For example, network customers change network resources from time-to-time due to cost and contractual considerations. Network loads change as well (*e.g.*, an auto assembly plant or some other large industry may open or close), sometimes without adequate notice. Other factors affecting the transmission plan include changes in loop flow and generator dispatch (*e.g.*, a network resource's fuel contract may expire causing it to operate differently or environmental restrictions may be imposed on a thermal or hydro plant). Overlaying this process with ongoing Commission review would be a prescription for endless litigation, particularly for utilities concerned about investment recovery, with a result that would be counterproductive to infrastructure investment.

Similarly without merit is NRG's request that transmission providers have an OATT obligation to construct upgrades to ensure service to all current and planned network loads under NERC's N-1 conditions.<sup>131</sup> This subject has been much discussed at NERC<sup>132</sup> and the

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<sup>131</sup> These LPPC reply comments assume that NRG uses "N-1" to refer to Category B events defined in NERC Reliability Standards. *See, e.g.*, TPL-002-0 at [http://www.nerc.com/pub/sys/all\\_updl/standards/rs/TPL-002-0.pdf](http://www.nerc.com/pub/sys/all_updl/standards/rs/TPL-002-0.pdf).

Commission is encouraged to deal with this in the context of reliability standards. There is an on-going debate over the degree to which NERC standards allow controlled (*e.g.*, not cascading) curtailment of local network load in response to certain transmission equipment outages (including those generally referred to as N-1). Transmission providers, including some LPPC members, have reasonably chosen to serve small, remote loads with a single radial line or single transformer bank. To do otherwise would make the cost of serving some small, remote loads unreasonably high in proportion to the cost of serving typical loads. When decisions about the amount of redundancy in the transmission plan do not compromise the reliability of the bulk-power system, LPPC believes the Commission should look first to state or local officials to make these fact-specific and sometimes difficult choices.

**b. Mandatory independent transmission planning oversight would not serve an effective or efficient purpose.**

There is no persuasive case to be made for the establishment of independent entities to oversee the transmission planning process, as argued by AWEA and EPSA.<sup>133</sup> The establishment of an independent entity would interject a needless layer of bureaucracy capable only of mischief, as transmission providers endeavored to carry out critical functions. The Commission's complaint procedure and its civil penalty authority are fully sufficient to police

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Category B is defined by NERC standards as the loss of a single bulk electric system element (*e.g.*, a generator, a transmission line or a transformer).

<sup>132</sup> See NERC Technical Issues Subcommittee ("TIS") Report to the NERC Board of Trustees - May 6<sup>th</sup>, 2006 - Agenda Item 12 - attachment 1 (available for download at <http://www.nerc.com/~filez/botagenda-0506.html>) especially the discussion of footnote b at p. 15 and the discussion captioned "Category B (Events resulting in loss of a single element)" at p. 17. The TIS recommended clarifications to transmission planning standards; however, the TIS report states at p. 17, with reference to Category B events (often abbreviated as N-1 events), that footnote b (of NERC Standard TPL-002) "does allow planned or controlled interruption of electric supply to some local network customers." While the Commission has not approved or disapproved any NERC standard, standard TPL-002, footnote b, does appear to conflict with NRG's proposal to modify the OATT to require service to all network loads under N-1 conditions.

<sup>133</sup> AWEA Comments at pp. 38-39; EPSA Comments at p. 37

transmission providers' obligation to abide by the OATT, and to hold open, transparent, and coordinated transmission planning processes.

### III. CONCLUSION

LPPC asks that the Commission adopt the positions set forth in LPPC's initial comments and articulated above in the Final Rule in this proceeding.

Respectfully submitted,

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Dated: September 20, 2006