UNITED STATE OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, LLC	:	Docket No. EL05-148-000
PJM Interconnection, LLC	:	Docket No. ER05-1410-000

Protest and Request for Rejection of Filing,
Or in the Alternative, for Hearing

Coalition of Consumers for Reliability:

Pennsylvania Office of Consumer Advocate
Maryland Office of People's Counsel
District of Columbia Office of People's Counsel
Ohio Office of Consumers' Counsel
Old Dominion Electric Cooperative
North Carolina Electric Membership Corporation
Delaware Municipal Electric Corporation
Allegheny Electric Cooperative, Inc.
Borough of Chambersburg, Pennsylvania
Illinois Citizens Utility Board
Southern Maryland Electric Cooperative
Virginia Division of Consumer Counsel
Indiana Office of Utility Consumers Counselor

Dated: October 19, 2005

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Pursuant to Rule 211 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.211, the Commission's Notice of Filing issued September 7, 2005 and the Commission's Notices of Extension of Time dated September 16 and September 23, 2005, Coalition of Consumers for Reliability ("CCR")[1] submit this Protest and Request for Rejection of Filing or in the Alternative for Hearing, to the filing made by PJM Interconnection, L.L.C ("PJM") on August 31, 2005 in the above-referenced dockets regarding its proposed Reliability Pricing Model ("RPM"). The CCR requests that the Commission reject RPM as unjust and unreasonable. Alternatively, the CCR requests that the Commission set this matter for hearing.

[1] Coalition of Consumers for Reliability consist of: the Pennsylvania Office of Consumer Advocate; the Maryland Office of People's Counsel; District of Columbia Office of People's Counsel; Illinois Citizens Utility Board; The Ohio Office of Consumers' Counsel; Old Dominion Electric Cooperative; North Carolina Electric Membership Corporation; Delaware Municipal Electric Corporation; Allegheny Electric Cooperative, Inc.; Borough of Chambersburg, Pennsylvania; Downes Associates; Southern Maryland Electric Cooperative; North Carolina Electric Membership Corporation; Virginia Division of Consumer Counsel, Office of the Attorney General; Indiana Office of Utility Consumers Counselor.

I. EXECUTIVE SUMMARY

The RPM proposal filed by PJM in these dockets will not ensure generation adequacy and fails to address the concerns PJM perceives with the current capacity market construct in PJM. As proposed, RPM makes unnecessary, sweeping changes to the current capacity construct without ensuring substantial benefit to consumers. First, RPM will dramatically increase costs to consumers without providing a corresponding, high level of assurance that reliability requirements will be met. Second, the RPM will disable the ability of demand response to act as a necessary counterweight to ensure competitive generation prices. Third, the RPM contains biases against potentially less expensive transmission solutions to transmission reliability problems.

The CCR actively participated in the stakeholder process leading to PJM's RPM filing. While extremely dissatisfied with the mechanics and substance of that process, as discussed in Section VIII below, CCR nonetheless participated at every stage in an attempt to ensure that any proposal filed by PJM would properly address the problems PJM perceives in the current capacity construct. Although the process did not result in a consensus on a capacity market design, it did provide the substantial background needed to initially assess the model filed by PJM. As demonstrated in this Protest, CCR opposition is based on a number of concerns that will be addressed in detail. Those concerns include:

- PJM's failure to show that the current capacity market system produces results that are "unjust and unreasonable;"
- PJM's failure to show that RPM, including an administratively determined demand curve (variable resource requirement or "VRR"), is either a reasonable or superior alternative to the current construct;

- PJM's failure to show that the significant price increases that result from the local premiums required under the RPM proposal will actually attract any new resources to local regions with transmission and environmental constraints;

- PJM's failure to respond to concerns that its proposal will produce "unjust and unreasonable" payments to existing base load generation;

- PJM's abandonment of the traditional format of its stakeholder process by refusing to engage in detailed discussion of alternatives to the basic components of the RPM and by precluding the stakeholders from developing consensus regarding alternative capacity adequacy models; and

- PJM's refusal to explore targeted alternative approaches to the problems that RPM purports to address.

As an alternative, the CCR urges the Commission to consider an approach that focuses on targeted solutions to the specific problems identified by PJM while steering clear of the sweeping redesign embodied in RPM. Targeted, incremental solutions are much more likely to produce successful, predictable results for the local reliability issues discussed by PJM in this filing. As addressed in more detail below, any proposed solution should address the following issues:

- Any capacity construct should seek to support the development of competitive markets instead of imposing administrative controls;

- Overly long forward commitments should be avoided so that demand response is capable of moderating the overall price of capacity; and

- The existing PJM transmission planning approaches to reliability and economic upgrades should be enhanced relative to scope and planning horizon, should incorporate known risks to reliability and should broadly promote competition.

II. STATEMENT OF ISSUES

1. Where PJM's filing should be rejected as improperly filed under Section 205 of the Federal Power Act ("FPA"), 16 U.S.C. § 824d?

2. Whether PJM's RPM proposal should be reviewed under Section 206 of the Federal Power Act ("FPA"), 16 U.S.C. § 824e?

3. Whether PJM has satisfied its burden under Section 206 of the FPA to demonstrate that the current capacity market construct is unjust and unreasonable?

4. Whether PJM has demonstrated that RPM will encourage adequate new investment in PJM, and resolve revenue adequacy concerns associated with certain classes of generating units in certain locations?

5. Whether a four year ahead auction model is necessary to attract adequate new investment in generating resources in PJM and is otherwise just and reasonable?

6. Whether a demand curve is necessary to attract adequate new investment in generating resources in PJM and is otherwise just and reasonable?

7. Whether PJM has demonstrated that the significant increase in costs for consumers associated with RPM is just and reasonable?

8. Whether the substantial capacity payments to existing resources that are not needed for operational flexibility and are not candidates for retirement are just and reasonable?

9. Whether more targeted solutions to PJM's perceived generation and revenue adequacy concerns can resolve PJM's concerns at a lower overall cost to consumers?

10. Whether this protest and accompanying affidavit have raised genuine disputes of material fact that require a full evidentiary hearing if the filing is not rejected?

11. Whether the Hobbs affidavit adequately supports the extensive changes PJM proposes to the current capacity market rules?

12. Whether the analyses described in the Hobbs affidavit support PJM's assertion that the proposed VRR produces greater reliability at lower cost to consumers than the current capacity construct?

13. Whether PJM has engaged in a meaningful and sufficient stakeholder process within the terms of the Operating Agreement to support its unilateral filing of changes to the current capacity market rules?

14. Whether PJM has adequately supported its assertion that the Enhanced Integrated Transmission Capacity Construct supported by PJM stakeholders is an inadequate alternative to RPM?

15. Whether PJM, through the stakeholder process, has adequately explored alternatives to its RPM proposal?

16. Whether PJM should abandon RPM and work with its stakeholders to implement an incremental and targeted solution such as the Enhanced Integrated Transmission and Capacity Solution discussed in detail below?

17. Whether PJM has the authority under Section 206 to move market rules from the OA to the OATT?

18. Whether market rules should reside in the OATT over which stakeholders have no approval rights regarding filings under Section 205?

III. INTRODUCTION

PJM adopted its current capacity construct as a fundamental pillar of reliability. This construct, contained in Schedule 11 of PJM's Operating Agreement, is based on the presumption of universal deliverability. Over time, the various markets in PJM, including the energy and capacity markets, together have produced price signals that result in rational outcomes. Specifically, these markets produced new investment in generation when the expectation of future prices was high and saw less frequent construction of generation when lower prices were expected. When competitive markets were first introduced in the late 1990s, generators anticipated high prices for capacity, and significant new investment entered the PJM capacity markets. More recently, under conditions of excess capacity in PJM, capacity prices have fallen and PJM is seeing a rational decline in the number of new projects in the generation interconnection queues.

PJM, perceiving this decline in new projects entering the queue to be a matter of concern, filed its Reliability Pricing Model as a broad scale re-engineering of its capacity market on August 31, 2005. RPM completely replaces existing market rules, changing the very nature of the existing capacity market construct. While the existing capacity market construct is based on robust bilateral transactions with an underlying auction where both buyers and sellers bid to secure a capacity product, RPM is an administrative model designed to ensure a floor of stable capacity revenues for generators with the intent of encouraging new investment in PJM. However, RPM, despite its extensive administrative intervention in the capacity markets, embodies substantial risks that new capacity will not be built in PJM, especially in those local areas with transmission and environmental constraints.

RPM constitutes an overly broad approach to resolving localized concerns, and will not accomplish the underlying goal of ensuring resource adequacy or revenue stability in PJM. PJM's existing capacity market design may contain some isolated flaws, such as inadequate compensation for certain types of inefficient existing units in local areas. However, on the whole, PJM's existing capacity market design, in conjunction with PJM's energy and ancillary market designs, produces just and reasonable prices for consumers, adequately encourages new investment in PJM and adequately compensates most generating units in PJM.

PJM's filing fails to prove that a wholesale redesign of its existing capacity market is necessary or even wise. The only thing that RPM will accomplish, other than unnecessary massive wealth transfers from consumers to generators, is administrative interference with, and masking of, the existing, reasonably accurate price signals for new investment.

IV. STANDARD OF REVIEW

A. Substantial Portions of PJM's Proposed RPM Market Rules Require Changes to the PJM Operating Agreement, Invoking Commission Review Under Section 206 of the Federal Power Act. This is Not a Section 205 Case.

PJM filed its RPM proposal under both Sections 205 and 206 of the FPA. In filing various aspects of its proposal under different FPA sections, PJM states that while it has the authority to file for revisions to its Open Access Transmission Tariff ("OATT") and it's Reliability Assurance Agreement ("RAA") under Section 205 of the FPA,[2] PJM does not have such exclusive authority over changes to the Operating Agreement. Instead, per Section 7.7 (vi) of the Operating Agreement, the PJM Board must file under FPA Section 206 proposed changes to that Operating Agreement for which it has not received the supermajority sector approval of the PJM Members Committee.[3] PJM's RPM proposal failed to receive the required supermajority sector vote of that Committee, thus requiring a filing under Section 206 for the modification to the Operating Agreement necessary to implement RPM.

The difference between PJM's burden of proof under Sections 205 and 206 of the FPA is significant. Section 205 requires only that the applicant demonstrate that its revised rates, tariffs and practices are just and reasonable.[4] However, filings under Section 206 require that the applicant first demonstrate that the existing rates,

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[2] We will address the flaw in PJM's analysis of its authority to make filings under the OATT and the RAA in Section B below.

[3] Section 7.7 (vi) of the Operating Agreement provides that the PJM Board may "[p]etition FERC to modify any provision of this Agreement or any Schedule or practice hereunder that the PJM Board believes to be unjust, unreasonable, or unduly discriminatory under section 206 of the Federal Power Act, subject to the right of any Member or the Members to intervene in any resulting proceedings". Section 8.4 (c) of the Operating Agreement provides that: "[T]he sum of affirmative Sector Votes necessary to pass a pending motion in a Senior Standing Committee shall be greater than (but not merely equal to) the product of .667 multiplied by the number of sectors that have at least five Members and that participated in the vote; . . .".

[4] 16 U.S.C. § 824d; *see also Southern Company Services, Inc.*, 23 FERC ¶ 63,018 (1983).

tariffs and practices are unjust and unreasonable and then demonstrate that the proposed replacement for those rates, tariffs or practices is just and reasonable.[5]

PJM attempts to skirt the Section 206 burden in this case by characterizing the majority of the changes to the Operating Agreement required to implement RPM as non-substantive in nature.[6] In fact, PJM states that the Operating Agreement changes being filed under Section 206 involve merely terminology changes to reflect the consolidation of the three RAAs, certain clarifying changes and ". . . the elimination, as mooted by RPM, of the existing daily and monthly capacity credit markets."[7] Although some of the required Operating Agreement changes may be non-substantive in nature, *e.g.* those consisting of clarification and changes in terminology, the core structure and rules governing all of PJM's markets, including the existing capacity market, are found in the Operating Agreement, thus requiring review under Section 206. PJM acknowledges this, admitting that ". . . this last change has substantive significance . . . ." *Id.* PJM attempts to excuse its legal burden under federal law with a claim that the existing market is deeply flawed. *Id.* No matter how flawed PJM believes this existing market to be, it cannot flagrantly ignore statutory requirements.

Examples of market rules included in the Operating Agreement can be found in Schedule 1 and Schedule 11. Schedule 1 contains the rules for the PJM interchange energy market. The schedule defines who qualifies to participate in the market, and contains the rules for scheduling and dispatch of that market, as well as the rules for Locational Market Prices, clearing of the energy market auction, calculation of

5 16 U.S.C. § 824e; *City of Winnfield, Louisiana v. Federal Energy Regulatory Commission*, 744 F.2d 871 (DC. Cir. 1984).

6 Transmittal Letter at 33.

7 Transmittal Letter at 34.

transmission congestion charges and credits, Reliability Must Run Generation designation and offer price caps. Schedule 1 of the Operating Agreement also contains the rules governing the Financial Transmission Rights auctions, the inter-regional transmission congestion management pilot program and the rules for participation in the emergency and economic load response programs. Most importantly, Schedule 11 of the Operating Agreement sets forth the existing Capacity Credit Market rules, including the auction clearing procedures, the bidding rules, the settlement procedures and the conduct of market operations.

Some of these market rules have counterpart terms and conditions in the PJM OATT or the RAA. The existing capacity market is one example. While the basic rules governing the auction, bidding requirements and auction clearing prices are all in the Operating Agreement, other elements such as the determination of the Installed Reserve Margin that establishes the capacity obligations for Load Serving Entities ("LSEs") in PJM are in the RAA. The rules for deactivating generating capacity in PJM's markets are contained in the OATT. However, the main components of the current capacity market rules are in the Operating Agreement. PJM seeks to eliminate those market rules from the Operating Agreement.

Although RPM is an administrative program, its implementation mechanics are marketplace-based, complete with auction clearing rules, bidding rules, and mitigation rules. Even the demand curve component is an economic component of the rule. PJM represents the purpose of the demand curve component to be promoting market competitiveness by addressing perceived economic inefficiencies in the existing market rules and by compensating for the lack of sufficient demand response.[8] These are all economic concerns. While RPM is an administrative proposal that addresses what PJM perceives to be reliability concerns, the reality is that many of the implementation aspects of this administrative model are based on marketplace interactions.

Many of the RPM provisions appropriately fall within the Operating Agreement. Approval of PJM's attempt to move these provisions to the OATT and the RAA would allow PJM now, as well as in the future, to avoid the Section 206 burden of proof for any changes to the capacity markets. As a result, in the future PJM would be able to propose changes to a fundamental component of its competitive market design solely under FPA Section 205. *Id.*

For the reasons discussed below, PJM's analysis of its relative burdens under Sections 205 and 206 of the FPA with respect to the RPM filing is flawed. The Commission should reject PJM's filing outright as improperly filed Section 205. Alternatively the Commission must review all of the proposed changes to the Operating agreement under the stricter Section 206 burden of proof, as opposed to the "just and reasonable" standard of Section 205. PJM's assertion that all RPM issues are reliability matters and therefore should be within PJM's Section 205 authority is an inaccurate portrayal of RPM. RPM does indeed address generation adequacy and reliability concerns; however, the existing capacity market rules and the implementation mechanisms surrounding RPM are rules for the PJM markets.[9] The rules governing the

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8 Transmittal Letter at 11.

9 In later sections, CCR discuss the administrative nature of the RPM proposal, in contrast to the market-based structure of the current capacity construct. Despite the administrative nature of the RPM mechanism (particularly the Variable Resource Requirement demand curve), RPM must be reviewed under the Section 206 procedures that apply to the Operating Agreement because it replaces existing market rules and is intended to be a "market structure".

construct of all of PJM's markets are contained in the Operating Agreement, not the OATT or the RAA. The Commission must not allow PJM, through this filing, to change the Operating Agreement requirements, in which the structure of PJM's markets require the vote of PJM's members, simply by shifting the capacity market provisions of the Operating Agreement to the OATT or RAA.

B. The Entire RPM Filing Requires a Section 206 Analysis as Market Rules Properly Belong in the Operating Agreement and the Proposed RPM Modifications to the OATT and RAA are Beyond PJM's Section 205 Authority under those Agreements.

The entire PJM filing, including those provisions PJM placed in the OATT and the RAA, are subject to the Section 206 burden of proof. RPM is a major redesign of PJM's capacity market rules. PJM cannot evade its Section 206 burden of proof to modify those market rules by carving up the rules and moving selected portions out of the Operating Agreement and into the OATT or the RAA. More importantly, even PJM's analysis that Section 205 governs its burden of proof over the RPM changes to the OATT and RAA is flawed. PJM's Section 205 authority under the OATT and RAA is limited to a narrow set of terms and conditions.

The PJM Operating Agreement reflects a careful division of Section 205 and 206 filing rights between the PJM stakeholders and PJM. At the time the stakeholders in PJM fashioned the PJM Operating Agreement, they determined that the rules governing the structure of PJM markets were of such critical importance to the financial interests of stakeholders that the stricter standard of proof under Section 206, limiting the authority of the PJM Board to make changes to those rules, was required.[10]

[10] *PJM Interconnection, L.L.C.*, 96 FERC ¶ 61,061 at Footnote 10 (2001).(in which the Commission noted that the Operating Agreement requires prior Member approval for use of Section 205 authority to

Essentially, the stakeholders transforming PJM into an RTO placed the rules governing the market transactions in the Operating Agreement so as to ensure that the stricter burden of proof applies to any changes to those market rules.[11] PJM has not sought the approval of the PJM Members to move the capacity market rules from the Operating Agreement.

Relative to the OATT, the issue of the proper division of rights under Sections 205 of the FPA between the Transmission Owners ("TOs") and PJM has a long and controversial history, having been appealed to the District of Columbia Circuit Court of Appeals more than once.[12] On October 3, 2003, PJM and certain of the TOs within PJM attempted to finally resolve this dispute through a Settlement Agreement in Docket Nos. OA97-261-006 *et al.* That Commission-approved Settlement addresses the rights of the Settling Parties to make filings under Section 205 of the FPA concerning their respective interests in the transmission facilities comprising PJM. The Settlement relegated to PJM a narrow set of Section 205 filing rights.[13] PJM may, subject to an obligation to consult with the TOs and the PJM Members Committee, file under Section 205 to change a) the terms and conditions of the PJM OATT; and b) the recovery of PJM's administrative costs.[14]

The Commission approved this Settlement, noting that "voluntary filing rights arrangements among the public utilities within PJM, whose rights would otherwise overlap, is consistent with Commission policy where . . . the interests of market

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make changes to that agreement; the Commission approved this structure as in compliance with the independence characteristic for Regional Transmission Organizations).

[11] *Id.*

[12] *Atlantic City Electric Company, et al. v. FERC*, 295 F. 3rd 1 (D.C. Cir. 2002) (Atlantic City I), *same case on appeal of remand* 329 F. 3rd 856 (D.C. Cir. 2003) (Atlantic City II).

[13] *PJM Interconnection, et al.*, 105 FERC 61,294 (2003).

[14] *Id.* at ¶ 11. While the Settlement provided for additional specificity as to the rights of the parties under the OATT, none of those provisions are relevant here. *Id.* at ¶ 12.

participants are safeguarded."[15] This Settlement in no way changed the separation of rights between the TOs and PJM specifically provided for in the Operating Agreement, but rather verified that PJM's Section 205 filing rights are of limited extent.

More importantly, this Settlement limits PJM's right to modify the OATT using its Section 205 authority to those matters specifically prescribed in the Commission-approved Settlement, *i.e.* terms and conditions of the OATT and PJM's own administrative costs. The terms and conditions that properly belong in the OATT are those incorporated in the Commission's *pro forma* OATT, *i.e.,* the terms and conditions for transmission service and generation interconnection procedures. Review of the Table of Contents of PJM's OATT reveals that the terms and conditions contained therein are consistent with the *pro forma* OATT, as amended by Order Nos. 2003 *et al.*[16] relating to generation interconnection procedures. In other words, PJM does not have the discretion to put anything it wants into the OATT as a means of avoiding stricter burdens of proof under other agreements. Only those terms and conditions properly within the realm of terms and conditions under the Commission-approved pro *forma* OATT are permissible. Matters beyond this limited set of terms and conditions, such as the market rules governing RPM, could only be added to the OATT under a Section 206 filing. This requirement properly protects the intent of the PJM stakeholders in placing certain matters, such as market rules, under the Operating Agreement.

Likewise, PJM does not have discretion to add anything it wants to the RAA through a Section 205 filing. While the Commission did give PJM Section 205

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15 *Id.* at ¶ 30.

16 *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, FERC Stat. & Regs. ¶ 31,146 (2003); *order on reh'g;* Order No. 2003-A, FERC Stats & Regs. ¶ 31,160 (2004); *order on reh'g;* Order No. 2003-B, FERC Stats. & Regs. ¶ 31,171 (2005); *order on reh'g,* Order No. 2003-C, 111 FERC ¶ 61,401 (2005).

filing rights to amend the RAA, the Commission limited the nature of the matters so included to IRM, capacity deficiency charges and other reliability parameters[17] as discussed in Section C below. PJM's attempt to expand its Section 205 filing authority to include market rules in the RAA goes far beyond the Commission intent in providing Section 205 authority over the RAA to PJM.

The Commission's approval of the split of filing rights between PJM and market participants under the OATT, RAA and the Operating Agreement recognizes that actions under the Operating Agreement can affect PJM's markets and the participants in those markets. The Commission's approval of the 2003 Settlement and the RTO compliance filing relegating to PJM a very narrow set of Section 205 filing rights under the RAA and OATT establishes the parameters for PJM action in this proceeding. The Commission did not intend, by this narrow delegation of Section 205 filing rights to PJM, that PJM could abolish the design of one of its fundamental markets under the lighter Section 205 burden of proof. The Commission should not allow PJM to undo the carefully crafted balance of filing rights contained in the Operating Agreement without first seeking the approval of the PJM Members Committee as provided for in the Operating Agreement. PJM's actions here attempt to end-run the limitations on its unilateral exercise of authority over the capacity market rules. PJM's position ignores the Commission's acceptance of the Operating Agreement that includes the very provisions PJM now seeks to replace. Adopting PJM's position would expand PJM's authority in a way never intended by the stakeholders or the Commission, and the Commission must not allow PJM to accomplish this objective.

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17 *PJM Interconnection, L.L.C.*, 96 FERC at ¶ 61,061 at 61,229-230 (2001).

C. The Commission Should Not Permit PJM to Evade Section 206 Scrutiny Under the Pretext of Following Inapplicable FERC Precedent.

PJM asserts that it should have Section 205 authority with respect to all aspects of RPM because the capacity market rules involve reliability issues.[18] PJM points to the Commission's previous determination that the PJM Board must have Section 205 authority over reliability matters in the PJM region as support for this argument.[19] However, PJM overstates the Commission's previous findings regarding the need for its Board to have Section 205 authority over reliability matters.

The RAA currently contains the rules governing the establishment of capacity obligations for LSEs in PJM's markets.[20] Those rules include the provisions governing the establishment of the forecast pool requirements for a planning period (including the Installed Reserve Margin ("IRM") on which those capacity obligations are based), the charges for capacity deficiencies and the allowable levels of active load management ("ALM").[21] PJM's argument that the capacity market rules address only reliability matters is without merit. Many provisions of the Operating Agreement address reliability issues as well as economic issues, as evidenced by the provisions in Schedule 9 relating to emergency procedures, Schedule 6 relating to the Regional Transmission Expansion Planning Process, Schedule 7 relating to under-frequency relay obligations and charges, and Schedules 8 and 8a relating to delegation of PJM control area reliability responsibilities. The mere fact that some matters address both reliability and economic issues such as the capacity market structure does not justify removal of market structure issues from the Operating Agreement.

18 Transmittal Letter at 33.

19 *PJM Interconnection, L.L.C.*, 96 FERC at 61,229-230.

20 *Id.* at 61,230.

21 *Id.* at 61,229.

In the order cited by PJM, the Commission expressed its concern that load serving entities ("LSEs") would have sole authority over the reliability requirements addressed by the RAA if they, rather than PJM, had Section 205 authority to modify the RAA. The Commission's decision to remove authority for setting the forecast pool requirement and IRM, as well as the rules for the capacity deficiency charges and ALM, from market participants and to relegate that authority to PJM's independent decisional authority was to ensure that responsibility for decisions involving a non-market good, *i.e.,* reliability, would remain within the realm of the independent PJM Board of Managers rather than subjecting critical reliability decisions to the dictates of those with financial interests in market outcomes. The Commission agreed that "allowing the LSEs rather than PJM to set the region-wide capacity reserve requirements is inconsistent with Order No. 2000" and, therefore, LSEs should not have the exclusive responsibility for setting reliability requirements that affect the PJM energy markets.[22]

While the Commission did state in those orders that the PJM Board should have Section 205 authority over the reliability matters in the RAA, the Commission did not mandate that any and all matters that PJM deems reliability-related must be within the PJM Board's Section 205 authority. To the contrary, the Commission has properly accepted the existing Operating Agreement, which specifically includes all market rules, including the market rules for the existing PJM capacity market. PJM's implication that the capacity market rules involve only reliability determinations is belied by the fact that those rules currently exist in the Operating Agreement.

PJM's arguments attempting to justify transferring the capacity market rules from the Operating Agreement to the OATT and the RAA ignore the Commission's

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22 *Id.*

acceptance of the Operating Agreement and the division of rights and responsibilities reflected therein.[23] The Commission should not condone PJM's attempt to expand its filing rights authority, and to treat its OATT and the RAA as a safe harbor for market changes that are not popular with its stakeholders. PJM has set forth no valid reason to move these provisions to the OATT or the RAA contrary to the intent of the stakeholders who helped draft and frame the Operating Agreement.

At the very least, the Commission should reject PJM's attempt to eliminate the provisions related to the existing capacity markets from the Operating Agreement. The Commission cannot lightly rewrite the basic market structure adopted in that Operating Agreement without imposing on PJM the heavier standard of proof to justify the need to change those market rules. Instead, the Commission should hold PJM to the Section 206 burden of proof for all of the proposed changes to the existing capacity credit market in the Operating Agreement. PJM has not met this Section 206 burden in this case and the filing should be rejected outright.

D. PJM's Reliance on Commission Approval of Capacity Market Changes in Other Regions Does Not Satisfy PJM's FPA Section 206 Burden to Prove that the Existing Capacity Market Construct is Unjust and Unreasonable.

As discussed in Section B above, even PJM acknowledges that certain aspects of its RPM proposal are subject to the stricter burden of proof under Section 206 of the Federal Power Act.[24] PJM attempts to meet that burden in part by reliance on Commission orders pertaining to filings by the New York Independent System Operator

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23 In this regard, the CCR also note that PJM is not barred from making a Section 205 filing under the Operating Agreement. With the requisite supporting votes, PJM can make Section 205 filings for changes to the Operating Agreement. *See* Operating Agreement Section 8.4(c). It is only when the PJM Board decides to make revisions to the Operating Agreement notwithstanding failure to obtain the requisite supporting votes that the Board must proceed under FPA Section 206.

24 Transmittal Letter at 34.

("NY ISO") and ISO New England, Inc. ("ISO-NE") relating to the redesign of certain elements of their capacity markets.[25][26] Those proceedings include the adoption of a demand curve in NY ISO and the on-going proceedings in New England to consider a locational component to New England's capacity market design.[27][28]

However, PJM cannot satisfy its Section 206 burden of demonstrating that its existing capacity markets and pricing are unjust and unreasonable by simply relying on the Commission's orders for other Regional Transmission Organizations ("RTOs") and ISOs, some of which are not yet final. In fact, the markets in New York and New England are clearly distinguishable from the PJM markets and circumstances, especially considering the current tight capacity situations in both the New York City load pocket and the rest of New York State, as well as the severe transmission constraints into southwestern New England. Further, it was appropriate for the NYISO to request a change under Section 205 because the NYISO Agreement explicitly allows a Section 205 tariff change if the NYISO Members Committee formally approves the change, which it did. No such approval has come from the PJM Members Committee.

The Commission's rulings related to the NY ISO demand curve are inapplicable to this case. In adopting the NY ISO demand curve, the Commission recognized the NY ISO's concern that financing for new generating facilities in New

25 Transmittal Letter at 25-30.

26 *New York Independent System Operator, Inc.*, 103 FERC ¶ 61,201 (2003); *order on reh'g* 105 FERC ¶ 61,108 at ¶ 39 (203); *aff'd Electric Consumers Res. Council v. FERC,* 407 F. 3rd 1232 (D.C. Cir. 2005) (*"ELCON"); See also Devon Power LLC, 103 FERC ¶ 61,082 (2003); order on reh'g Devon Power Company et al.* 104 FERC 61,123 (2203); *order on compliance filing Devon Power, LLC* 107 FERC ¶ 61,240 ("*Devon I*"), *on reh'g* 109 FERC ¶ 61,154 (2004) ("*Devon II*"), *on reh'g* 110 FERC ¶ 61,315 at ¶ 14 (2005) ("*Devon III*").

27 *Id.*

28 Transmittal Letter at 28-29.

York had become scarce, leading to potential capacity deficiencies in the region.[29] The Commission found that the existing capacity market in New York promoted "extremely volatility" in capacity prices in the region.[30] The Commission further recognized that the demand curve in New York resulted from negotiations among the stakeholders in that region, culminating in the support of the majority of New York ISO members, as well as the New York Public Service Commission.[31]

The greater volatility in capacity prices in New York is not unexpected considering the tight capacity conditions in both New York City and the rest of New York State. Neither extreme volatility in current capacity prices nor tight supply conditions exist in PJM. Thus, the fact that the Commission's approval of the New York demand curve was upheld on appeal has no bearing for this PJM proceeding considering the significantly different market conditions in PJM. Additionally, while the majority of stakeholders in New York supported the NY ISO demand curve proposal, the same is definitely not true of PJM's RPM proposal. As discussed in Section VIII below, PJM undertook no effort to reach consensus among its stakeholders on RPM.

Nor does the Commission's approval of LICAP and a demand curve in ISO NE provide support for PJM's RPM filing here. In *Devon Power LLC and Devon Power Company, et al.* the Commission, after reviewing several requests for reliability-must-run ("RMR") contracts, found that the existing capacity market rules in New England did not produce a just and reasonable result because those rules may not allow suppliers "an adequate opportunity to recover their costs and that a location-specific

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29 *NY ISO,* 103 FERC at ¶ 4.

30 *Id.* at ¶ 31.

31 *Id.* at ¶ 53.

capacity requirement must be in place."[32] The Commission ordered the ISO to file a locational capacity market or a deliverability requirement for implementation by June 1, 2004 to correct the deficiencies of the existing capacity structure.[33] The conditions in the ISO-NE proceeding stand in stark contrast to those prevalent in PJM. PJM initiated this filing; it was not ordered to do so by the Commission. In contrast with ISO New England, the Commission has not determined that the current PJM capacity construct does not provide suppliers an adequate opportunity to recover their costs. That is PJM's Section 206 burden in this proceeding.

Although both the ISO-NE LICAP and PJM RPM proposals use an administrative price schedule (demand curve) to set capacity prices, the two approaches are entirely different. RPM is a four years forward auction with a one year firm payment commitment. LICAP is less than one year forward and payments are adjusted monthly. The RPM target is IRM +1% while the LICAP target is IRM + 5%. The maximum capacity to be purchased under RPM is IRM +5% while the maximum to be purchased under LICAP is IRM +15%. These differences are sufficiently critical as to require review of evidence in relation to PJM's specific proposal and market conditions.

PJM's reliance on the Commission's order in PJM's local market power mitigation proceeding in Docket No. EL03-236-000 *et al.* likewise contains no merit. There, the Commission rejected PJM's proposal to implement a local market auction where insufficient capacity exists in local regions and price signals do not result in new investment.[34] While the Commission in *dicta* there noted that locational requirements for installed capacity could provide stable revenue streams under certain circumstances, the

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32 *Devon Power LLC, et al.*, 103 FERC ¶ at ¶ 31; *Devon Power Company, et al.* 104 FERC at ¶ 33.

33 *Devon Power LLC,* 103 FERC at ¶ 37.

34 *PJM Interconnection, L.L.C.,* 107 FERC ¶ 61,112 at ¶ 19-21 (2004).

Commission was speaking of theory and not specific circumstances in PJM. In fact, the Commission there made no finding that PJM's current capacity market required a locational component.

PJM must provide sufficient evidence, specific to the PJM region, that the existing capacity construct is unjust and unreasonable, and that RPM is the just and reasonable solution. PJM simply has not done that here. Considering the significant differences between conditions in both New York and New England from those in PJM, the Commission cannot rely on findings relevant to those regions that are not supported by the evidence in this proceeding.

As discussed in Section V below, PJM has failed to satisfy its Section 206 burden of demonstrating that the existing capacity market design and pricing construct is unjust and unreasonable. The New York ISO and ISO New England orders provide no support for PJM's filing. PJM has not even established that the RPM proposal satisfies the lower standard of proof under Section 205 of the Federal Power Act. For these reasons, the Commission should: 1) review PJM's filing to revise the Operating Agreement under the requisite just and reasonable standard of Section 206, 2) not allow PJM to escape its Section 206 burden by citing inapplicable precedent, and 3) determine, that PJM has failed to satisfy its burden under both Sections 205 and 206 of the Federal Power Act.

V. PJM Did Not Meet Its Burden Under Section 206 To Show That The Current Capacity Construct Is Unjust And Unreasonable.

PJM alleges that there are several flaws in the current capacity construct. To the extent that the Commission finds that these flaws exist, they can be more appropriately addressed through modest, incremental and targeted solutions as discussed below. The current construct has in the past, and continues today, to encourage adequate new investment in PJM, and produces sufficient revenues for most generators at just and reasonable prices for consumers.

A. PJM's Existing Capacity Market Design Provides Accurate Price Signals and Encourages Adequate New Investment.

PJM incorrectly argues that the current capacity construct cannot attract capital to finance investment in generation because "it is not providing sufficient financial incentives for supply additions",[35] "nor has it demonstrated the capability to sustain generation investment" (Ott Affidavit at 13:22-27). This proposition flies in the face of actual PJM market experience. Available capacity in PJM today, and into the next decade, exceeds requirements by a substantial amount, demonstrating that ample capacity has been attracted to the region.

PJM's existing market design is based on a single clearing auction price for energy and a single clearing auction price for capacity, with Locational Market Prices ("LMP") for energy reflecting the cost of congestion on the transmission grid. The combination of that energy and capacity market structure encouraged many generators, mostly gas-fired units, to rush into the PJM generation interconnection queues.

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35 Transmittal Letter at 5.

As of October 11th 2005, 16,535 MWs of generation have entered service and another 2,745 MWs of generation is under construction.[36] PJM has a capacity margin approaching 25%,[37] well in excess of the 15% reserve margin required by PJM, and generally projects sufficient resources at the system level into the start of the next decade.[38]

Active projects in the generator interconnection queues have increased to 23,475 MWs.[39] Of this 23,475 MWs, based on past experience, not all projects should be expected to come on-line.[40] These resource candidates include roughly 8,600 MWs of coal and just fewer than 7,000 MWs of wind (electric basis).[41] The resource mix reflects a rationale response to market conditions for fuel costs and capacity prices under the current construct.

B. Locational Problems are the Result of Flaws in Transmission Planning.

Economic theory dictates the price of an over-supplied product should be relatively low. The current capacity prices documented repeatedly by PJM's market monitor in PJM's State of the Market Reports demonstrate that the existing PJM capacity market merely reflects these fundamental economic and market principles. Considering the over-supply in PJM's existing market, the current low capacity prices send the proper signal to investors to slow the rate of investment in this market. PJM's overall market

36 See the summary of new resource additions since generator interconnection request queue "A" was opened in 1997 at ftp://ftp.pjm.com/pub/reports/planning/rto/20051011-RTO.pdf and http://www.pjm.com/planning/res-adequacy/downloads/20051011-mw-new-generation.pdf

37 http://www.pjm.com/contributions/news-releases/2005/20050501-dominion-integration.pdf

38 http://www.pjm.com/planning/res-adequacy/downloads/20051011-forecasted-reserve-margin.pdf

39 A summary of this information can be found at http://www.pjm.com/planning/project-queues/report-rto.jsp as of October 11th 2005 as well as for prior periods.

40 In the more mature generator interconnection request queue group A-C which produced about 75% of the resource additions 73% of projects were withdrawn as shown at http://www.pjm.com/planning/project-queues/queues-printable.jsp.

41 Detailed project breakdowns can be found at http://www.pjm.com/planning/project-queues/queues-printable.jsp.

design, including the existing capacity market construct, is acting just as it is supposed to, given rational economic and market theory.

Capacity prices have not collapsed as PJM suggests, but rather range at times between $20 to $100/MW-day. The existing robust bilateral capacity market provides additional evidence to belie PJM's theory.[42] The current capacity market properly reflects price signals that match sound market fundamentals, *i.e.,* capacity prices are low when excess capacity exists in the market. With existing system-wide capacity surpluses projected by PJM into the next decade, it would be irrational for significant investment to be made today in generation that is highly dependant on capacity revenues. It would be equally irrational to revise PJM's capacity model to promote such investment except where it is clearly needed in specific, local areas.

Another explanation for the recent, relatively low capacity prices produced by the existing capacity market construct today could be PJM's lowering of the Installed Reserve Margin ("IRM") in the past several years. IRM is the amount of capacity reserves required to satisfy reliability standards. In response to the fundamentally more robust character of the expanded PJM RTO, PJM lowered IRM several hundred basis points.[43] This action permitted LSEs to purchase less capacity to satisfy their lower level of capacity obligations. These changes in IRM were, at times, made just prior to the beginning of the new planning year. While the reduction in IRM was justified due to the diversity added by the expansion of PJM's borders, the changes in IRM happened on

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[42] *See generally* 2004 PJM State of the Markets Report.

[43] The PJM planning process has tended to adjust the required reserve margin sometime just prior to the applicable calendar or planning year as historically shown at http://www.pjm.com/markets/capacity-credit/parameters.html. Note the expansion of PJM into to new market areas also has appropriately lowered the reserve margin. As a result, the IRM of 20% for planning year 1999-2000 has been gradually reduced based on sound engineering to 15% for planning year 2005-2006.

short time horizons, sometimes after investment may already have been committed. This reduction in demand relative to supply on a short horizon may well explain in part the fall in capacity prices in PJM.

The current energy and capacity market design has proven to encourage new investment. In times of oversupply, prices should be low and consumers should benefit. RPM will deprive consumers of lower prices during periods of over-supply by establishing an artificial floor for capacity prices and by providing substantial capacity payments to much of the excess generation in the market. Owners of baseload units stand to profit the most from RPM, since these owners will reap substantial capacity payments from RPM in addition to the infra-marginal revenues they earn in the energy markets and the billions they collected from consumers in stranded cost payments. Artificially sweetening the monetary returns for existing generators will only further enrich those generators.

C. PJM's Concerns that the current Capacity Market Produces Inadequate Revenues for Certain Units Is Misplaced.

PJM also relies on what it perceives to be inadequate capacity revenue streams for certain types of generating units as support for the proposition that the existing capacity market is no longer viable.[44] This concern is misplaced. The rush to construct new units in response to PJM's existing overall market design was complemented by a rush to buy existing units from those utilities seeking to divest their production facilities. Many of these utilities had received substantial payments from their retail customers with the blessing of their state regulatory commissions in the form of "stranded costs" for these plants. Much of this divestiture occurred at two to three times

[44] Transmittal Letter at 7.

book value in response to expectations of high market prices for electricity. Generators purchased many of these units as a "package." These packages included both some efficient, competitive units as well as inefficient and non-competitive units.

This analysis demonstrates that the existing capacity market design not only produced a glut of new capacity, but also produced a number of "new" generation owners who overpaid for their assets. RPM will pay these existing generation owners substantially more for this capacity, thus discouraging or delaying the necessary financial restructuring (e.g. sale or write-downs) or retirement of inefficient units. Should the Commission find any merit in PJM's concerns with the inadequacy of capacity revenue streams for certain generators under the existing market rules, those concerns are better addressed through solutions targeted to those generators as opposed to the broad market redesign inherent in RPM.

D. Locational Problems are Primarily the Result of Flaws in Transmission Planning and Insufficient Retirement Notification Lead-times.

PJM identifies what it perceives to be a lack of a locational component in the existing capacity market construct to send appropriate signals to site new generation in certain local areas.[45] The current capacity market design is based on the presumption of a robust transmission system that does not yet exist. There are areas within PJM where existing capacity needed for reliability has not been retained and new capacity needed for reliability has not been sited. The problem has been exacerbated by a deficient transmission planning process and an insufficient retirement notification lead-time, not an inadequate capacity construct. While the presumption of universal deliverability may no longer be appropriate, this factor does not justify wholesale

45 Transmittal Letter at 5-6.

remodeling of the capacity market construct and repudiation of the price signaling role of LMP.

The existing construct has been sufficient to induce significant quantities of new generation investment in PJM. Specifically, natural gas cost increases have driven up clearing prices substantially even while the production costs of base-load coal and nuclear generation has remained fairly stable in comparison.[46] When energy prices are added to expected increases in capacity prices under any construct, including the status quo, developers are seeing clear price signals. As depicted in Table 1, this is particularly clear in local areas.

Table 1
7x24 LMP (real-time)[47]

Hub ($/MWh)	1999	2000	2001	2002	2003	2004	2005 (jan-sep)
Eastern	28.79	30.52	37.00	29.40	39.32	45.86	62.19
Western	27.98	27.17	29.45	27.50	37.21	42.35	56.75
Change in West from 1999 (as $/MWh)							
	0.00	(0.81)	1.47	(0.48)	9.23	14.37	25.42 *(to jan-sep 99)*
East over West (as $/MWh)							
	0.81	3.35	7.55	1.90	2.11	3.50	5.44

If it is necessary to modify the existing capacity construct to recognize documented deficiencies in isolated local areas, then an incremental and targeted approach to fix the specific problem is the only just and reasonable approach. Adopting an entirely new market design that will not cure the perceived flaw in the existing design

[46] PJM in the 2004 SOM report (pg. 67-71) goes to great length to detail that the energy market outcomes are competitive for the market and auction design selected. Even so, substantial increases in natural gas and crude oil during 2004, continuing into 2005, has provided substantial increases in infra-marginal revenue to assets like nuclear, coal, and hydro that supplied over 92% of the energy in 2004 (also PJM 2004 SOM pg. 44 Figure 1-6).

[47] Calculations of historical real-time LMP from http://www.pjm.com/markets/jsp/lmpmonthly.jsp.

fails the test for just and reasonable rates to consumers required by Sections 205 and 206 of the Federal Power Act, 16 U.S.C. §§ 844d and 824e.

One example of a more targeted solution is to modify the existing capacity construct to attract new or retain existing resources.[48] Another reasonable alternative is to lengthen the required lead-time for retirement notification. The current rules require only 90 days notice of retirement intent. Either option would directly address one of PJM's perceived concerns with isolated locational issues regarding generation retirement or revenue adequacy

PJM emphasizes the need for geographically small local areas that potentially change frequently. Herling Affidavit at 10. However, PJM fails to consider the alternative of responding to such concerns through the transmission planning process. That process can reduce the need for such narrow areas by better integrating recognition of both transmission constraints and generator retirements in the process.

Even with its locational premiums, for the reasons we will discuss at length below, RPM will not necessarily encourage the development of new generation where it is most needed, *i.e.,* in those local areas experiencing high LMPs and a low rate of new generation construction. New units could come on line, but the innate infrastructure deficiencies of inadequate transmission capacity and diversity of fuel supply that create the current local problems in PJM would likely remain. New units responding to RPM's price signals, like new units today, would still be more likely to locate in favorable local areas, *i.e.*, areas with robust transmission, diversity of fuel supply, reasonable environmental constraints, and relatively attractive LMP.

48 See the discussion of EITCC in Section VII. That model seeks to modify the existing capacity construct by addressing locational price signal issues on a more targeted basis.

E. The Current Capacity Construct Relies Not on Short-term Markets, But on Longer Term Bilateral Arrangements and Multi-Month Auctions.

PJM incorrectly asserts that the shorter clearing horizons and commitment periods in the current capacity construct result in an over-reliance on short-term capacity markets.[49] PJM further incorrectly asserts that longer commitment horizons are necessary to make sure participants satisfy obligations, and that the current construct lacks the necessary long term forward commitments needed for accurate price signals. *Id.* These statements ignore the reality, as demonstrated below, that well over 98% of all capacity in PJM trades in longer term bilateral arrangements and multi-month markets.

TABLE 2
PJM Unforced Capacity Credit Market Auction Clearing Results[50]

Credits as Percent of Obligation (unforced)

	2004	**2003**	**2002**	**2001**	**2000**	**1999 (jun-dec)**
Daily	1.4%	1.4%	0.8%	1.5%	2.5%	0.7%
Monthly	1.4%	1.1%	1.5%	1.2%	1.2%	0.5%
Multi-monthly	3.9%	4.2%	3.8%	1.0%	1.8%	1.4%
Total Credits	6.7%	6.6%	6.1%	3.7%	5.4%	2.6%
Previously Purchased	93.3%	93.4%	93.9%	96.3%	94.6%	97.4%

As demonstrated in Table 2, even under today's daily capacity requirement, almost no participants wait until the last opportunity to acquire needed capacity. These statistics from the PJM Market Monitoring Unit show that roughly 95% of obligations are satisfied via bilateral agreements. The daily market only satisfies about 1% of

49 Transmittal Letter at 8-9, 48.
50 Calculations on the unforced capacity credit market historical MMU data found at http://www.pjm.com/markets/market-monitor/cap-market-data.html and the PJM State of the Market Report 2004.

obligations. Looking back multiple years as summarized in Table 3, over half of these credit auctions, making up only 5% of total obligations, are satisfied by multi-month or one year duration auctions.

Table 3
Detailed Historical Auction Results[51]

UCC Auctions (~5% of the Market Volume)	Volume		Expenditure	
(Jan 1st 1999-Oct 17th 2005)	MW-day	% of total	$s	% of total
Daily	2,241,857	24%	$67,901,232	24%
Monthly	1,948,985	21%	$67,174,647	23%
Multi-Monthly (< year)	3,257,249	35%	$101,586,622	35%
Year	1,974,487	21%	$51,654,988	18%
Total	9,422,578	100%	$288,317,490	100%

PJM's suggestion that shorter clearing horizons under the existing capacity market construct is inappropriate because LSEs might fail to secure capacity in time to satisfy requirements during the planning year[52] is not supported by this data. As can be seen in Table 4 below (calculated from data that PJM posts on its website under the Market Monitoring Unit link), virtually no participants lean on the market. Only three one thousandths of one percent of capacity in 2004 was not covered in advance by the LSE that had the obligation.

Table 4
Unforced Capacity Obligation Not Cleared

Obligation Not Cleared as a Percent of Obligation (Unforced)	2004	2003	2002	2001	2000	1999 (jun-dec)
Not cleared	0.003%	0.004%	0.061%	0.337%	0.076%	0.013%

The multi-month capacity auctions in PJM provide for adequate price discovery and result in just and reasonable prices for capacity. It is inaccurate to argue, as PJM does, that price signals for properly defined obligations cannot work when the

51 *Id.*

52 Transmittal Letter at 8-9, 22, 48.

final auction takes place only a few months prior to the planning year. This defies the historical experience of other commercial market transactions. Since supply and demand generally clear in most commodity markets, most participants in those markets make their purchases in advance of the required delivery for the products. PJM's capacity markets are no exception.

F. PJM's Concern Over the Inadequacy of Revenues for the "Most Efficient Marginal Capacity Unit" is Misguided.

PJM presents the Affidavit of Dr. Benjamin Hobbs as an attempt to justify RPM and the values used in the demand curve component of RPM. PJM's arguments appear to contain an implicit assumption that the capacity market design must always produce sufficient revenues for the marginal incremental investment in PJM, that the marginal investment should be a combustion turbine facility, and that its failure to earn a full return in capital reflects a market failure.[53] This argument is reminiscent of regulated resource planning in the sense that location, size and technology of required generation is determined by the regulator, in this case, PJM.

The marginal investment is not necessarily a combustion turbines (CT) plant.[54] Based on a review of PJM's generation interconnection queue, substantial portions of recent supply additions have been from a diverse set of resource types.[55] These include new CT, gas combined cycle generators, and new baseload units. In addition, significant capacity was added through the expansion of capacity across a diverse technology spectrum of existing generation units. Contrary to PJM's assertions

[53] Transmittal Letter at 7.

[54] It is entirely reasonable for an individual investor to assume the marginal investment should be a CT plant and then to invest accordingly as long as the individual participant bears the consequences of the investment and assumption. It is not just or reasonable to dictate that the marginal investment is a CT and all buyers and sellers must involuntarily transact at a price based on this assumption on a distant horizon.

[55] http://www.pjm.com/planning/project-queues/queues-printable.jsp

and its modeling assumptions, the marginal investment, unlike regulated investments within vertically integrated utilities, is not necessarily a small, expensive, dual-fuel, peaking facility.

Not all assets require the same return or the same capacity revenue stream. It is entirely conceivable that a new coal plant or an expansion to an existing plant might make sense while a new peaking facility may not. PJM and Dr. Hobbs incorrectly assume that the necessary value and variability of capacity revenue for an investor is the same for every generation source. The risk aversion of investors is also a function of the individual participants and the lead-time required for a specific investment. Thus, a fundamental assumption of the Hobbs' study must be called into question. This further undermines the basis for PJM's conclusions regarding the RPM.

Not all generating resources receive insufficient capacity revenue and any revenue shortfall cannot be generally determined through an equilibrium model. However, excess supply in a capital-intensive industry, such as the electricity industry, should produce low prices and sub-par returns for some. Low prices today should not be confused with low prices in the future. Not all resources are "missing money," as highlighted by two recent studies by Synapse Energy Economics, Inc., of the likely impacts of RPM.[56] These reports clearly depicts how increasing infra-marginal energy revenues for certain baseload assets more than offset any justifiable declines in capacity revenues.

Only a small percentage of the capacity in PJM is potentially revenue inadequate. The real issue with adequacy for the next several years is with the small

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[56] These two reports address likely revenues under RPM for baseload generation resources in Pennsylvania (http://www.synapse-energy.com/Downloads/Synapse-report-pa-oca-cap-rev-pjm-06-05.pdf) and Illinois (http://www.synapse-energy.com/Downloads/Synapse-report-il-cub-eh-pp-dw-bb-rpm.pdf).

number of the highest cost units that run infrequently and thus receive sparse infra-marginal energy revenues that can contribute to profitability. For example, in 2004, nuclear, coal, and hydro resources comprised 64% of PJM's installed capacity and 92% of the megawatts hours generated in PJM. (2004 PJM State of the Market pg 44). Absent unusual licensing or environmental circumstances, the cash flows of these assets are substantially positive and they are unlikely to retire in the next five years. Likewise, a substantial portion of oil- and gas-fired resources in PJM have positive cash flow compared to avoidable costs, even on an energy only basis. Some of these resources are already committed over a number of years via long-term tolling contracts.

It is not acceptable to overlay an administrative solution providing for full return on a particular low returning asset class and then pay this price to all assets. Certain lower-utilization assets, but for unique circumstances (*e.g.*, local value), might never earn a full return going forward, especially if economics drive additions of baseload resources which push these less efficient units further up the supply stack. It is fundamentally unjust and unreasonable to guarantee at the start of deregulation that each asset class earn, on a going-forward basis, a full return on capital on average.

PJM provides substantial analysis in the PJM 2004 State of the Markets Report, but then reaches incorrect conclusions.[57] Several relevant observations should be considered:

- Assets general do not earn a full return on capital when there is excess supply in capital-intensive industry;
- Lower utilization assets like CTs suffer relatively more than higher utilization assets when there is excess supply;

[57] Transmittal Letter pg.71-86.

- Assets with higher utilizations and less dependent on capacity revenue are relatively earning a high return and are closer to supporting new investment make sense; and
- A narrow local area issues or problem due to inadequate retirement notification lead-times does not invalidate the general lessons from PJM's new entry analysis.

It is reasonable to expect that there will be uneven returns among various types of assets in a deregulated industry. However, it is not acceptable to overlay an administrative solution providing for full return on the least-efficient asset class and then pay this price to all assets. Certain lower-utilization assets, but for unique circumstances (*e.g.*, local value), might never earn a full return going forward, especially if economics drive additions of baseload resources which push these less efficient units further up the supply stack. It is fundamentally unjust and unreasonable to guarantee at the start of deregulation that each asset class earn, on a going-forward basis, a full return on capital on average. Wedding out the inefficient units is the exact point of moving toward competitive markets in the fist place.

G. <u>PJM's Assertion that There is Excessive Volatility under the Current Capacity Construct is Inaccurate</u>.

PJM argues that the current capacity construct will produce substantial volatility in capacity prices over time, thus increasing risk and prices for consumers in the long run.[58] However, capacity prices in annual and monthly markets are not excessively volatile, properly reflect demand and supply conditions, and are reasonable in light of the existing PJM capacity model. As discussed earlier, the current construct does not clear either at $0 or at the capacity deficiency rate as suggested by Dr. Hobbs. Hobbs Affidavit at 4-5. Instead, capacity prices frequently clear well above $0 on a forward basis even though supply and demand fundamentals would suggest otherwise. This is because there

58 Transmittal Letter at 6-7.

is perceived risk to not acquiring capacity ahead of time even when there is a substantial market surplus.

Volatility is only periodically more apparent in the daily market where a very small proportion of capacity market purchases occur. Specifically, as noted above in subsection V.E, the daily capacity market accounts for about 1% of the cleared volume in all PJM-administered capacity markets.

These facts suggest that volatility in capacity prices does not rise to the level of concern that would require wholesale redesign of the existing capacity market construct. Thus, PJM's argument that the capacity model must be changed in order to prevent volatility contains no merit.

PJM claims that RPM will reduce capacity market price volatility at a cost PJM considers reasonable. This approach ignores actions that individual participants can take independent of an administrative market design. Wholesale market participants that believe the current construct is too volatile and costly can capture the purported benefits that PJM claims for RPM through a less expensive bilateral transaction in the existing market design. A number of generators in PJM "wagered" that the price of these bilateral transactions would increase substantially, hence their decisions to purchase former utility assets at significant premiums following restructuring. These factors also influenced a number of generators who entered into long-term tolling contracts for natural gas fired combined cycle plants. These merchants acted based on some incorrect assumptions, and now they find themselves seeking a change in the rules in order to cover potential losses resulting from their own decisions.

H. <u>The Current Capacity Construct Does Not Create Undo Uncertainty for the Transmission Planning Process</u>.

PJM staff and other RPM supporters stress the critical importance of matching the forward commitment period to the transmission planning horizon.[59] These assertions are simply wrong. In fact, planning in PJM has been a successful tool, within the limits of the factors that are considered. It is the nature of planning that the fundamental information used is statistical in nature but with known and limited variability. Thus, while predictions about the future state of the system are themselves uncertain, this does not invalidate planning. Instead, it informs market participants, as well as the RTO that is responsible for regional reliability, that a range of outcomes is possible.

In PJM's case, the range of possible outcomes has historically been at a relatively low level of uncertainty. That made it relatively straightforward to assess system adequacy and to develop solutions to protect reliability. PJM's initial planning process began as the member utilities first unbundled. The mix of assets in place was based on coordinated least-cost planning with known quantities for generation availability, location and performance. Applying a transmission planning process appropriate for a vertically integrated, bundled paradigm, in combination with an unprecedented amount of new generation in PJM's interconnection queue, made the early years of PJM's transmission planning fairly straightforward. However, as markets evolved, the transmission planning protocol was not modified to reflect the new realities of a competitive marketplace. Unfortunately, potential violations of reliability standards are beginning to arise. These are due to the inability of the existing planning model to

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[59] Transmittal Letter at 14.

address problems that are known, but occur beyond the fixed 5-year planning horizon in PJM's existing transmission planning process and due to the failure of that process to consider reasonably knowable risks of generation retirement.

One reason that PJM did not anticipate recent load deliverability problems in New Jersey was that PJM's planning system did not incorporate the known risk of generation retirement.[60] As PJM now recognizes, this risk can and should be incorporated into planning. Just as the existing planning system incorporates the expected failure rate of generators without naming them publicly, the characterization of retirement risk can be done without impugning any particular generator or group of generators.

It is necessary to enhance the scope and extend the planning horizon of PJM's transmission planning process to accommodate today's market uncertainties. Such expansion will greatly facilitate any capacity market model by allowing generating facilities to site in logical locations. Regardless of the capacity market model, transmission (especially regulated) infrastructure plays a predominant role in the siting of new generation resources and thus necessarily leads the resource. It is just a question of whether the investment criteria are based on minimalist reliability standards or standards more likely to foster competitive markets. In essence, generation resources will site where the transmission infrastructure is robust, where there is an adequate and, hopefully, diverse fuel supply, and where there are minimal environmental concerns. If these conditions do not exist and generation units serve as substitutes for transmission capacity, shorter-notice retirements cause problems.

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[60] At the technical conference (PL05-7), it was explained that several of the units retiring which posed problems have not run in the last two years (Transmittal Letter 149:23-25). Screening criteria should have flagged this scenario for action.

Although the bulk of units are not at risk of retirement, there may be situations where a local area faces unacceptable reliability risks. These local risks can be addressed through a variety of targeted approaches that include a more robust transmission planning process, a local area capacity adder, an increase in retirement notification periods, or short-term RMR payments. Merely including local area problems under the umbrella of an overhaul of the entire capacity market design will result in excessive payments to the majority of resources.

I. PJM's Assertions That Operational Flexibility has Declined and that Modifications to the Current Capacity Market are the Best Response are Unfounded.

In a series of stakeholder discussions and a white paper[61] PJM assessed the concern of declining offers for operational flexibility in existing markets and recommended incorporating compensation for load following and certain reserves in the RPM model.[62] The evidence in that analysis reveals that PJM may have misdiagnosed the problem, and overstated the difficulty, time and relative cost to resolve any issues in energy and ancillary services markets. As a result, PJM may have selected a potentially sub-optimal solution via RPM.

PJM asserts that it has seen a decline in the operational flexibility offered by generators into the energy markets. This declines includes less dispatchable generation and fewer units available for multiple starts in a day or too few units with short minimum run times. PJM has suggested that the decline in offers for operational flexibility is driven by increased maintenance costs. PJM explains that older fossil-fired steam units that have traditionally provided more of the load following have been retiring

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61 See http://www.pjm.com/committees/working-groups/pjmramwg/downloads/whitepaper-rpm-reliability-metrics.pdf

62 Transmittal Letter at 46-47.

and bemoans the lack of flexibility that newer resources have such as combined cycles. PJM additionally suggests there is no appropriate incentive or compensation method for generators to provide these services.

During the stakeholder process, the CCR argued that the specific operational requirements for units that are available to supply load-following or other necessary services can be effectively addressed through modifications to existing markets. PJM has resisted such options, arguing that implementation of market solutions would require expensive new software to address a perceived need for more frequent settlement within the hour such as sub-hourly settlements.

PJM has misdiagnosed the situation as well as the solution. If PJM's contention regarding higher maintenance costs is accurate, generators should be capable of increasing bids in existing markets to account for these cost increases unless there are inherent limitations that preclude units from doing so profitably as in the past.[63] Since older fossil-fired steam units that have traditionally provided load-following have been able to offer similar services without sub-hourly settlement, then sub-hourly settlement should not be assumed to be necessary for operational solutions, especially if implemented in existing energy markets. Even if these load following services are procured under RPM, it is unclear how this service is going to be obtained since no sub-hourly settlements are included even though PJM suggests this feature is essential to the service for energy and ancillary service solutions. In addition, PJM incorrectly states that new resources such as combined cycles are not flexible in terms of being able to

63 This last statement actually holds the key. All other things equal a unit should be able to adjust offers to profitably take advantage of satisfying the market. As the style of generation has changed, PJM has failed to provide unit commitment and offer flexibility in such a way for gas turbine based technology to do what it is capable of doing.

technically provide load following and cycling. If this were true, then it is unclear what new technology PJM thinks it is going to attract under RPM that will provide this service. Perhaps PJM assumes that price increases from RPM will prolonging the lives of inefficient fossil-fired steam units.

Market-oriented approaches external to the capacity construct are more appropriate to address specific operational issues for generation, especially when discussing the best way to fairly compensate characteristics that inherently exist within reliable energy and capacity markets. Rather being allowed to simply assert that RPM is the best way to procure these services, PJM should first determine whether existing resources are capable of providing such services and, if so, why such services are not being offered under the current market design.

Load following problems may be the result of PJM's failure to develop a suitable unit commitment cost model for multi-unit combined cycle plants[64]. Such a model would allow a flexible asset to efficiently price the variability in output. Also, any root cause analysis on multiple starts or flexible run and start times should further consider whether the rules governing existing energy offers are appropriate, *e.g.* whether only allowing market based start charges to change twice a year and failing to allow units to price multiple starts or dispatches at a different price on a given day require modification.[65]

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64 PJM requires steam based-resources to submit energy offers in ten segments of increasing price versus output but a multi-unit combined cycle has costs which look like a declining saw tooth as output increases. There is no easy way for this combined cycle to offer its wide range of operational flexibility with PJM's software limitations or the unit may price itself out of the market at full output. A typical output curve for a CC without supplemental firing can be found in Figure 33 on pg. 18 of the General Electric reference document GER 3767c at http://gepower.com/prod_serv/products/tech_docs/en/downloads/ger3767c.pdf.

65 The bulk of new generation has been gas turbine based. These units have significant maintenance costs determined as a complex function of starts and operating hours. PJM's failure to allow flexibility in

To the extent the projected reliability issues require action by Planning Year 2008-09 as RPM assumes, the Commission should assess PJM's past success with incremental changes to resolve operational issues. For example, during the summer of 1999, PJM determined that its market rules provided improper incentives to generators for reactive support. PJM's rules allowed the dispatch of generators at a lower level than offered in order to provide the desired level of reactive support, leading to a concern that the incentives for providing reactive support were distorted since generators were not compensated for the lowered output of their units. PJM resolved this concern by implementing energy make-whole payments. Another example is the difficulty PJM had some years ago attracting sufficient regulation services. Generators had perceived that the market rules in existence at that time provided insufficient compensation for regulation service. PJM resolved that concern with the creation of a new regulation market.

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changing certain parameters given the range of maintenance cost outcomes effectively creates inflexibility that does not need to be created.

VI. PJM's RPM Proposal Is Not Just And Reasonable

A. The Near-Term Economic Impacts of the RPM Proposal Will Impose Substantial Burdens on Consumers.

The costs of reliability are ultimately paid by consumers and, under RPM; consumers will pay much more for reliability than in the past. The CCR's preliminary analysis of PJM's filing leads to the conclusion that the annual incremental cost of RPM will be in the range of $5 billion per year across PJM. This estimate is based on graphical rather than numerical information and uses estimates for load growth as forecast by PJM and the demand curve information provided in PJM's filing. Unfortunately, in its filing, PJM has not presented a specific estimate of the near-term impacts of the RPM. Nonetheless, the CCR's preliminary analysis provides a reasonable estimate based on available information, promising substantial price increases for PJM consumers. That alone raises serious questions regarding the value of the RPM. Generator revenues under RPM are wildly out of proportion to customer benefits. Two studies project impacts of RPM on capacity costs were performed by Synapse Energy Economics. The first study was done in June 2005 for the Pennsylvania Office of Consumer Advocate, one of the CCR. That study projected capacity revenues for a sample of baseload generating units in PJM's PECO and PPL Zones using PJM's simulations developed for the RPM Working Group in January 2005.[66] The study used historical revenues that were secured by these units under the existing PJM capacity construct and determined that annual capacity revenues for the six plants in the study, representing a total of about 6,600 MW, will increase by between $130 million and $200

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66 The Report is available at http://www.synapse-energy.com/Downloads/Synapse-report-pa-oca-cap-rev-pjm-06-05.pdf.. The units are Exelon's coal-fired Eddystone 1 and 2 and Limerick 1 and 2 (nuclear), PPL Generation's coal-fired Montour 1 and 2 and Susquehanna 1 and 2 nuclear plants.

million by 2009. The second study was completed in October 2005 for the Illinois Citizens Utility Board, also one of the CCR. That study projected capacity revenues for six Exelon nuclear power stations serving Northern Illinois using the target capacity price of the RPM. For approximately 11,000 MWs of resources, annual capacity payments will increase in a range from $315 to $385 million.[67] These two studies encapsulate one of the CCR's fundamental concerns, namely, that consumers will pay substantially more to existing generators under RPM but for no incremental improvement in reliability.

B. <u>The Demand Curve Would Raise Costs To Consumers With No Corresponding Benefit</u>.

One component of the RPM proposal is the replacement of the clearing mechanism in the current capacity construct with a downwardly sloping demand curve or VRR. PJM asserts that this will result in "reduced risk and volatility, greater reliability, and lower consumer costs."[68] PJM's assertions have no merit. Mr. Jonathan Wallach has evaluated PJM's claims regarding its demand curve proposal and concludes in his attached affidavit that:

> PJM's assertions regarding the advantages of the VRR are based on a mischaracterization of the current construct and its impact on market prices. Moreover, when system capacity exceeds required margins, the proposed VRR arbitrarily and artificially forces auction prices to clear at levels that exceed marginal supply costs or even the marginal value of capacity to consumers. This attribute of the VRR not only needlessly increases costs to consumers and windfall profits to generators, but also reverses one of the few consumer benefits from restructuring by re-imposing the cost of uneconomic capacity on consumers.[69]

[67] The report is available at http://www.synapse-energy.com/Downloads/Synapse-report-il-cub-eh-pp-dw-bb-rpm.pdf.

[68] Transmittal letter, p. 9.

[69] Affidavit of Jonathan F. Wallach, attached hereto as Tab A ("Wallach Affidavit"), p. 5.

1. PJM incorrectly characterizes the current construct as producing extreme price volatility.

Characterizing the current clearing mechanism as "similar" to a vertical demand curve, PJM claims that, under the current construct,

> … prices are very high if there is a shortage of only a few megawatts below the IRM, but drop to zero if there is a surplus of only a few megawatts of excess capacity above the IRM level.[70]

PJM mischaracterizes both the nature and dynamics of the current clearing mechanism. Mr. Wallach, in his affidavit, points out that, contrary to PJM's assertion, "the current clearing mechanism for the monthly and multi-monthly auctions does not employ a vertical demand curve to clear supply offers."[71] Mr. Wallach explains that under the current mechanism the markets are cleared against curves created from actual buy bids of market participants.[72] In stark contrast with the administratively determined VRR, these demand curves represent market-buyers' determinations of the value of capacity.

PJM also mischaracterizes the impact of the current clearing mechanism on price volatility. Mr. Wallach provides the data to shown that capacity-market prices over the last six years have not oscillated between the capacity deficiency rate and zero. Instead, prices have declined steadily as supply margins have increased over time.

2. The demand curve does not reduce total capacity costs.

PJM makes the claim that the demand curve actually results in a savings of total capacity costs when more capacity is necessary to meet IRM is procured. According to PJM:

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70 Transmittal letter, p. 8.

71 Wallach Affidavit at p. 6.

72 *Id.*

> When the VRR curve clears above the IRM, i.e., commits more capacity than the 15% margin, the <u>overall</u> cost of all capacity to the market (not simply the unit cost) is lower.[73]

Mr. Wallach explains that "[t]he total cost of purchases in excess of IRM is less than that for purchases at IRM only when such purchases are at the artificial price levels set by the demand curve. When compared to the cost of purchases at IRM under the current construct, the total cost of purchases in excess of IRM under the VRR is significantly higher."[74] Mr. Wallach demonstrates this fact by fully explaining an example used by PJM.[75] In the PJM example, it is pointed out that using a demand curve can result in less total costs to procure 18% reserves (about $209,000 per day in the example) than to procure 15% reserves (about $129,000 per day).[76] However, PJM's conclusion is only valid if all purchases are made at some point along the demand curve. Mr. Wallach demonstrates that in PJM's example enough capacity for a 15% reserve margin could be procured for about $69,000 per day using a clearing price of the marginal unit needed for a 15% IRM.[77] This would be the basic method used today to clear all the PJM markets. When viewed in relation to the current construct, the requirement to purchase excess capacity under the VRR will significantly increase, not decrease, total costs to consumers and windfall profits to generators.

3. The demand curve results in customers paying prices higher than the highest bid in times of excess capacity.

The unjust and unreasonable results that occur with the use of a demand curve as proposed by PJM are also demonstrated by Mr. Wallach's explanation of how it

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73 Transmittal letter, p. 11.

74 Wallach Affidavit at p. 8-9.

75 *Id.* at 9-10.

76 *Id.*

77 *Id.* at 10.

is used to set prices in situations where more supply than is needed is bid into the market but the supply ends before intersecting with the demand curve. In this situation, all the capacity bid into the market clears and the price is set by drawing a vertical line from the end of the supply curve, which is the highest bid price, to the demand curve. This will force purchase of excess capacity at artificial price levels that exceed marginal supply costs, thereby further enriching both infra-marginal and marginal capacity resources.

Mr. Wallach explains that in PJM's example, more capacity than is needed is bid into the market and the highest bid is \$80/MW-day.[78] However, the demand curve results in a clearing price of about \$115/MW-day.[79] So, load has purchased all the capacity bid into the market, which is in excess of what is needed to maintain reliability, yet the price is set above the highest priced bid.

Mr. Wallach explains that this type of price setting provides no benefits in terms of useful investment signals that might overcome the obvious harm to consumers that it creates.[80] Mr. Wallach, who participated in PJM's stakeholder process on RPM, also explains that this is more than a hypothetical concern because in many of the market simulations presented by PJM during those meetings, which have not been filed with the Commission, the RPM markets cleared in this fashion.[81]

4. PJM's proposed demand curve will result in purchases of capacity in excess of IRM at prices that exceed the value to consumers.

Mr. Wallach describes how PJM initially proposed a demand curve based on the value of lost load ("VOLL").[82] Early in the stakeholder process, PJM proposed a

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78 *Id.* at 11.
79 *Id.*
80 *Id.* at 12.
81 *Id.*
82 *Id.* at 12-13.

demand curve that pegged prices to estimates of the VOLL. At least conceptually, this would result in consumers paying no more than the value of the excess capacity that was purchased as a result of the demand curve. However, PJM abandoned the value-based curve in favor of a curve designed to ensure "revenue adequacy" to generators. Mr. Wallach explains that "the revenue-adequacy-based curve generates prices that are considerably higher than the value to consumers for quantities in excess of IRM." [83] Mr. Wallach concludes that:

> as long as there is excess capacity on the PJM system, PJM's preferred demand curve will procure excess supply at prices that exceed the marginal value of that excess capacity. These above-value payments lead to inefficiencies in resource allocation, retaining excess capacity that should be either sold into higher-value markets outside PJM, written down, sold off at a loss, or shut down.[84]

C. <u>The Hobbs analysis is not persuasive</u>.

PJM bears the burden of proving that its proposal to use a demand curve to establish prices under RPM will produce just and reasonable results. This task is made more difficult by the facts described above, specifically that the demand curve results in purchases of capacity in excess of what is required for reliability, sets price above the marginal bid in times of excess capacity, results in higher total cost than the current clearing method of clearing PJM markets, and forces consumers to pay more for capacity than its value in terms of preventing the loss of load. PJM buttresses its argument supporting the demand curve approach on analyses performed by Professor Benjamin

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83 *Id.* at 13.
84 *Id.*

Hobbs.[85] There is a serious lack of data on these two analyses at this stage of this proceeding. Most importantly, PJM has not shared the spreadsheet model used by Dr. Hobbs with its stakeholders. Mr. Wallach points out a number of questions that PJM leaves unanswered by this lack of information.

> ...PJM has not provided the Commission or other parties a working version of the dynamic model or any model results on an annual basis and in sufficient detail to determine: (i) whether the model reasonably simulates near-term system conditions in PJM, particularly with respect to the current state of excess supply; or (ii) how many years in the future before long-term benefits outweigh near-term cost increases. This latter shortcoming is especially problematic, since the reasonableness of the RPM proposal may hinge on benefits that don't start accruing until several decades in the future.[86]

Despite limited information, Mr. Wallach identifies a number of deficiencies that render Dr. Hobbs' analysis unreliable. As such PJM cannot reasonably rely on Dr. Hobbs' analysis in attempting to meet its burden of showing that the demand curve produces just and reasonable results. This section addresses the Hobbs analysis, and the next section of this protest addresses the Ott analysis.

Dr. Hobbs evaluated a variety of capacity constructs, with different versions of a demand curve, on the basis of 100-year average results, as well as volatility around those averages as measured by the standard deviation over the 100-year horizon. Mr. Wallach describes how "Dr. Hobbs' simulation of the vertical demand curve is not representative of market clearing under the current capacity construct, and thus provides no useful information regarding the likely long-term impacts of the current construct."[87]

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85 PJM also relies on an analysis by Mr. Andrew Ott. Mr. Wallach's evaluation of that analysis is discussed in the next section of this protest.

86 *Id.* at 15-16.

87 *Id.* at 14.

Dr. Hobbs uses a simulation of a vertical demand curve as representative of the current capacity construct and draws his conclusions based on the differences between his modeling runs using a vertical demand curve and other demand curves. This approach is completely undermined by the Mr. Wallach's demonstration that the current construct cannot accurately be described as using a vertical demand curve to clear the market and, in fact, "allows for buy bids and thus market clearing against a market-based, sloped demand curve."[88]

Mr. Wallach also finds that the Hobbs analysis suffers from a number of defects, including i) "[m]ethodological flaws", ii) "[u]nrealistic and unreasonable input data assumptions," and iii) "[i]ncomplete evaluation of the impacts of alternative demand curves."[89] Mr. Wallach's findings are provided in detail in his affidavit and summarized below.

First, the Hobbs' analysis uses average results over a 100-year simulation period. The CCR has made a preliminary estimate that the implementation of RPM increase costs to consumers by $5 billion per year over the near term. PJM does not provide any analysis of the costs and benefits of the demand curve approach over the next decade or two decades, only Dr. Hobbs' 100-year average results. As stated by Mr. Wallach: "Judging the reasonableness of a market construct based on estimations of impact 100 years in the future is unprecedented, and an analysis period of 100 years is well outside the bounds of what is generally accepted as a reasonable planning horizon for forecasting exercises."[90]

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88 *Id.* at 14.
89 *Id.*
90 *Id.* at 15.

PJM carried out a separate modeling effort during the stakeholder process to examine the near term effects of RPM. However, it has apparently abandoned that effort and has not included any information on it with its filing.

Second, Mr. Wallach shows how unrealistic input assumptions "rig the game" in favor of a sloped demand curve.[91] Primarily, "it is abundantly clear that Dr. Hobbs's simulation of a vertical demand curve artificially imposes extreme volatility in prices and investment cycles by assuming that both existing and new resources would irrationally bid capacity at a zero price…"[92] Mr. Wallach points out that this assumption of zero bidding not only contradicts PJM's own proposal for using a non-zero marginal cost for capping of generator bids, but also is contrary to the basic theory of uniform pricing in energy markets, as expressed in a report co-authored by Dr. Alfred Kahn.

> Under the present uniform-pricing rules, suppliers in an effectively competitive market have every reason to bid approximately their marginal opportunity costs for energy in each of the blocks of power that they offer. They know that if any of those bids is rejected because there are sufficient lower bids to satisfy the demand, they will be better off, because they will not have committed themselves to sales at prices that fail to cover their avoidable costs.[93]

Mr. Wallach concludes that the false assumption of zero bidding leads to "a dramatic over-estimate of expected costs to consumers and profits to generators, and substantial understatement of average system adequacy under a vertical demand curve."[94]

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91 *Id.* at 16-21.

92 *Id.* at 16.

93 *Id.* at 17-18, *quoting* Alfred Kahn, *et al*, "Pricing in the California Power Exchange Electricity Market: Should California Switch from Uniform Pricing to Pay-as-Bid Pricing?," study commissioned by the California Power Exchange, January 23, 2001, p. 3.

94 Wallach Affidavit at p. 17.

Third, Mr. Wallach points out several sensitivity analyses and demand curve alternatives that are not included in Dr. Hobbs' analysis. Mr. Wallach describes how there is a dramatic improvement in results for the vertical demand curve when using more realistic bidding assumptions. Mr. Wallach states:

> Given the dramatic impacts from using more-realistic bidding assumptions, which more closely comport with economic theory and practice, it would have been reasonable for Dr. Hobbs to have repeated his sensitivity analyses on a base case that incorporated these assumptions. In addition, it would have been reasonable for Dr. Hobbs to have evaluated alternative versions of the vertical demand curve, just as he had done for the VRR. Two feasible alternatives would be: (1) a vertical curve at IRM+1%, similar to the IRM+1% VRR curve; and (2) a curve that is vertical at IRM, and that slopes up from the net cost of new entry to the capacity deficiency rate for quantities below IRM (as discussed below.)[95]

Also, PJM provides sensitivity analyses which indicate that there is no benefit to consumers to the sloped portion of the demand curve for quantities greater than IRM. Mr. Wallach explains:

> For example, with PJM's preferred IRM+1% curve, reducing the vertical-curve point from IRM plus fourteen percent to IRM plus ten percent has no impact on consumer payments or generator profits, and only slight impact on average reserve margins. The same holds true when the vertical-curve point is reduced from IRM plus ten percent to IRM plus five percent.
>
> This result begs the question as to whether the Dr. Hobbs's simulation would yield comparable results if the vertical-curve point were reduced all the way down to the inflection point for the various curves, at which point the "sloped" demand curve would be non-vertical only for quantities below the inflection point. If so, then Dr. Hobbs's model would be showing that there is no apparent long-term value to clearing of capacity in excess of IRM (or IRM+1%), since costs and performance are comparable

95 *Id.* at 22.

whether the vertical-curve point is at IRM or IRM plus five or ten percentage points.[96]

In other words, the model results could be indicating that the long-term benefit under RPM of a sloped demand curve case relative to a vertical curve is solely or largely attributable to the sloped portion below IRM (or IRM+1%).[97]

Based on his review of the information provided on Dr. Hobbs' analysis, Mr. Wallach concludes: "It is thus unreasonable to rely on the results of Dr. Hobbs' analysis as the basis for replacing the current construct with the proposed RPM."[98]

In addition, a careful review of the graphs related to the Hobbs analysis in PJM's Transmittal letter show some significant variations from the graphs provided to the RPM Working Group in January 2005.[99] While some of those discrepancies may be explained by the new shape of the VRR that PJM has proposed for this filing, PJM has not provided an explanation for these changes. CCR maintains that a full explanation of the variations is essential for a full understanding of both the methodology used by Dr. Hobbs and the results that methodology produced.

D. PJM's estimate of energy-cost savings with a VRR is flawed.

PJM has provided an analysis performed by Mr. Andrew Ott that purports to show that the use of a demand curve in procuring capacity will result in substantial savings in energy prices. The methodology used by Mr. Ott is directly contradicted by Dr. Hobbs' analysis. Mr. Ott's assumes that there will be more capacity on the system with RPM in place and that the difference in total capacity on the system with RPM in

[96] In contrast, consumers benefit in the near term by moving the vertical-curve point closer to IRM. As discussed above in Section IV.B, purchases of excess capacity at demand-curve prices are more costly than purchases at IRM at the marginal cost of supply per the current clearing mechanism.

[97] *Id.* at p. 23-24.

[98] *Id.* at 15.

[99] One example is the reduced volatility in ICAP prices of the PJM preferred VRR (IRM +1%) in the Transmittal letter (Hobbs' Affidavit, Attach. H, at 42) when compared to the same VRR in a RJM RAM Stakeholder WG presentation on January 26, 2005.

place and without RPM is made up entirely of base load plants.[100] He implements this assumption by removing generation from his case with RPM based on the age of the generating plant, starting with the oldest plants. Mr. Wallach points out that this approach is contrary to "theoretical expectations–as supported by Dr. Hobbs's findings–that increases in installed reserves will not materially reduce energy costs under non-scarcity conditions."[101] In contrast to Mr. Ott's approach, Dr. Hobbs' analysis assumes that "incremental capacity is provided by benchmark combustion turbine (CT) capacity."[102]

The flawed assumption that makes up the foundation of Mr. Ott's analysis deprives it of any usefulness. The Commission should give no weight to its conclusions.

E. <u>The Four Year Time Horizon Of RPM Will Harm The Markets</u>.

PJM has failed to show that the current capacity construct is unjust and unreasonable yet it continues to claim that the extended clearing horizon is necessary to overcome an over-reliance on short term markets, to reduce the risk of participants not satisfying their obligations, and to signal price signals sufficient to attract investment. PJM then goes further and claims that this extended 4-year clearing horizon is necessary for generation and transmission to compete. Not only are these claims without merit, the CCR views that this change is harmful to the market on several fronts as described below.[103]

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100 Ott Affidavit at p.25.

101 Wallach Affidavit at 26.

102 Hobbs affidavit, p. 22.

103 Even if PJM's claims have merit, force clearing the entire market on an extended 4-year horizon is excessive and therefore unjust and unreasonable. If and only if it is determined to be reasonable to force the market to fully clear out past the lead-time for certain physical resource solutions, then a horizon past 6-18 months is unnecessary. PJM appears to erroneously reach this conclusion based on a schedule provided by Mr. Pasteris (Transmittal letter pg. 75-76) that shows a combustion turbine (CT) plant taking as much as 4-years from concept to full commercial operation. Per the RPM business rules, a planned project after the

1. An unnecessarily long-term commitment is harmful to the market

There are four main problems associated with RPM's forced clearing of the entire market four years in the future. First, because individual LSE obligations four years in the future are unknown, PJM is forced into an inappropriate procurement role in place of individual buyers and sellers managing their own obligations and risk. Some have recently suggested that PJM is not really buying and selling, but just setting the price through the auction. This is a semantic distinction without a difference. Supply and demand for the entire market is forced to clear in an auction on an extended horizon, creating an effective obligation for all loads to purchase capacity at the auction-clearing price.

Second, this extended forced clearing interjects artificial scarcity into the auction, since the forced mechanism clears 100% existing load plus all four years of growth other than a small set-aside for demand response.

Third, this extended forced clearing stifles the bilateral market. Since all participants are essentially fully hedged for the next four years, participants have little risk left to manage during this meaningful period of what should be dynamic price

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transition period must have executed a Facility Study Agreement (FSA) to offer into the primary auction. The project schedule by Mr. Pasteris (affidavit pg. 23) has the FSA occurring roughly one and a half years into this four schedule. Without even evaluating whether more tasks can be pursued in parallel or customary practices result in shorter lead times, PJM has overstated the resource commitment horizon by at least one and a half years. As covered elsewhere, "solving" generation and transmission simultaneously does not actually occur in practice and this does not justify this longer clearing horizon.

However, as evidenced by the generator interconnection queue and customary practice, it is not uncommon for projects to complete some of the early development work and stay in a "incubation" status so they can be built quicker when the market opportunity is right. Developers may have multiple projects in various stages of readiness depending on the required investment at that point and their view of ultimate development success and the market opportunity. CTs may take between 10-18 months to build from where logical pauses in development actions occur. Using 18-months for a CT project is not unreasonable. Similarly, diesels depending on the permitting process may take from 6-12 months. Combined these suggest a reasonable lead-time if physical resource solutions must be allowed for is no more than 6-18 months or much less than the 4-years proposed under RPM.

discovery by individual market participants.[104] PJM has suggested that the bilateral market would evolve to this new construct and claim that, similar to when PJM converted to LMP pricing, the fears concerning bilateral agreements are misplaced. (Affidavit pg. 83-84) In terms of the bilateral capacity market evolving to this new structure, however, PJM has yet to offer a compelling explanation on what incentive most market participants would have to manage their risk and hedge exposure in such a way to enter into a bilateral not starting for five years on an item that would become a common pass through charge, much like capacity would become under RPM.

With regards to misplaced fears on bilateral contracts following PJM conversion to LMP, it is true that the bilateral energy market flourished particularly at hubs. However, in the shift to LMP, consider if a centralized auction had been added where 100% of the projected energy volume for four years would have been cleared against an administrative price curve on behalf of all participants, as in RPM. Under this scenario, the successful bilateral trading market that exists today would not have occurred. This is important because investment in new generation has tended to be based on bilateral contracts.

Fourth, concerns regarding RPM's potential interference with demand response continue to exist. This is troubling because eventually most hope that demand response can discipline the market and help deliver the benefits of competition.

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[104] A market place is composed of buyers and sellers with a variety of horizons on which risk is managed. The interaction of buyers and sellers that tradeoff price and term ranging from the shortest horizon near delivery to several years out (especially year 2, 3, and 4) is how a competitive market price gets discovered. While the responsibility of an individual participant, there is a strong incentive to manage one's risk and avoid being "wrong" or too far off from market. Lengthening duration or the term to improve price on a capital asset is common and rationale. RPM eliminates this vital interaction and forces all buyers and sellers to be essentially fully hedged for four years and thereby removes the primary incentive that drives individuals to enter into a bilateral agreement and reduces the consequence of being wrong.

The CCR does not believe that RPM's forced clearing on extended horizons can be accomplished when the party serving the load is managing the obligation. Additionally, the CCR would suggest that any modifications should be directed towards improving the clarity of the future obligation (e.g. adjusting reserve margins with greater notice or adding a reasonable stable local element to the general resource adequacy obligation) for the market over arbitrary forced clearing of the market on extended horizons. In contrast to RPM, EITCC contains features that would workably define obligations further into the future over force clearing of the market on extended horizons, including a three-year horizon on the system IRM and a local area obligation for a portion of the obligation in a few relevant areas.

2. <u>PJM overstates its argument that RPM is synchronized with the RTEP process and that transmission and generation compete</u>.

PJM continues to claim that RPM yields an integrated solution by allowing generation (and demand response) to compete against transmission in the RPM auctions.[105] This is true only with respect to merchant transmission, which can offer into the RPM auction in the same manner as a generation resource.[106] Given potential differences in lead-times and the lack of detail behind how this occurs it is all together unclear how meaningful this merchant transmission would be in the market.[107]

RPM originally failed to consider a long enough planning horizon such that certain transmission upgrades may have been excluded from practical consideration, to consider economically at risk units, or to broadly evaluate if the transmission investment criteria were suitable for a competitive market place. As initially proposed,

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[105] Transmittal Letter p. 3, 81-83.

[106] The same holds true for capacity auctions under the EITCC construct.

[107] Given the little development in PJM's economic transmission, it would be hard to consider this merchant transmission as a significant element until shown otherwise.

the RPM construct unreasonably favored uncertain, short-term capacity commitments over longer-term regulated transmission upgrades for resolving deliverability violations. RPM implementation would then forestall long-term transmission solutions that provide certainty regarding local deliverability so long as sufficient local capacity commits for only one year to meet deliverability requirements. In this respect, RPM perpetuates and exacerbates the current problems of generators' local market power by failing to accommodate long-term transmission solutions, which may be more efficient in the long run.[108]

In the RPM filing, PJM effectively acknowledges many of the issues raised around the transmission planning process by pointing to a series of needed reforms.[109] Interestingly enough even, while conceding the transmission planning process is in need of reform, PJM states "While the current planning process inherently is biased towards transmission solutions, RPM will bring a neutral long-term auction approach that favors only the lowest-cost solution, regardless of whether that is transmission, generation, or load management."[110] This is very telling. The current transmission planning process is based on a minimalist reliability investment standard. Circumstances are such that PJM's Board recently directed certain initiatives associated with transmission such as longer planning horizons and a more robust economic planning process (May 31st 2005 letter from PJM Board to PJM Members).[111] This makes PJM's

108 Although not yet reviewed or explained in detail with the stakeholders, PJM did recently add a new provision intended to at least partially address the problem of continuing to pay higher prices for local areas by indicating that a regulated transmission solution would be eventually triggered after two years under the RTEPP process (Transmittal Letter pg. 17-18). While it is unclear if this sufficiently deals with all the underlying concerns, it is at least a positive step.

109 Transmittal Letter pg. 13-15.

110 Transmittal Letter pg. 14.

111 Many of the improvements being contemplated in transmission parallel many of the original suggestions included in EITCC.

description of the current transmission planning process as "inherently is biased towards transmission solutions" all the more amazing. In practice under the status quo or any capacity alternative including RPM and EITCC, regulated transmission necessarily leads resource investment as the basic equivalent of the highway system. The predominant question is what is the transmission investment standard or criteria. Given PJM's characterization, it is premature to credit either PJM or RPM with integrating or allowing regulated transmission to provide the necessary competitive infrastructure or to compete with generation.

With regard to the issue of simultaneously solving generation and transmission, and the growing importance of this issue under longer planning horizons, the CCR reaches different conclusions.[112] First, PJM understates the level of certainty that they have today for the overwhelming majority of resources. Second, PJM overstates the degree of higher certainty obtained under RPM because resources can still fail to perform or buy out of an auction. Also, the Joint Protesters do not consider the possible minor improvement in certainty under RPM worth the excessive cost of RPM. Third, transmission planning further out makes major improvements to the grid more likely which fosters a more competitive market place. Transmission planning that considers a certain range of "what ifs" is more likely better positioned to deal with the inherent uncertainties of a complex system and to offer more flexibility when encountering an unanticipated outcome.

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112 Herling Affidavit pg. 6-7

F. The Reliability Backstop mechanism is not sufficient to maintain reliability.

PJM includes in RPM a mechanism it refers to as a "Reliability Backstop."[113] The main component of this mechanism is an auction for capacity resources that will receive revenue through the PJM tariff for a period of up to fifteen years.[114] The proposed tariff states that PJM will seek permission from the Commission to hold such an auction if "the total Unforced Capacity of all Capacity Resources committed through Self-Supply or the Base residual Auctions for four consecutive Delivery Years, equates to an installed reserve margin that is more than one percentage point lower than the approved PJM Regional Installed Reserve Margin…"[115] PJM will begin the auction process after the Commission directs it to do so in response to PJM's filing.

The auction process begins with the opening of a bid period. The proposed tariff provisions state that the offer period will open no later than four months after the fourth consecutive Base Residual Auction that failed to procure sufficient capacity or base load generation.[116] However, that is subject to the prior approval by the Commission.[117] PJM proposes a six month offer period.[118] After which, winning bidders

113 Proposed Tariff Attachment Y, Section 16.

114 *Id.* at Section 16.4.

115 *Id.* at Section 16.3.1. Similarly, if there is insufficient Base Load Generation committed in four consecutive Base Residual Auctions, PJM will seek permission to hold an auction targeted to obtaining additional Base Load Generation Resources.

116 *Id.* at Section 16.4.a).

117 *Id.*

118 *Id.*

would be determined and a contract would be executed. The contract would become effective after filing and acceptance by the Commission.[119]

The mechanism proposed by PJM is deficient because it delays actions, in situations where new capacity is needed for a delivery year but developers are not willing to commit capital based on the market rules that comprise RPM until well beyond the point that a backstop mechanism can correct the deficiency. RPM is a new and untested concept, and there are many unanswered questions about how it will work in practice. There is a legitimate concern that one year of revenue certainty, albeit four years in the future, is not sufficient for developers of new capacity. Some mechanism to assure that reliability is achieved under RPM is necessary. However, PJM's proposal does not allow for a backstop auction to occur unless the Base Residual Auction, which is conducted four years ahead of the Delivery Year, does not procure enough capacity to be within one percentage point of meeting the Installed Reserve Margin for four consecutive years.

After the fourth consecutive Base Residual Auction that does not clear sufficient capacity, there will be only about a month before the beginning of the Delivery Year for the first in the series of four deficient auctions.[120] In the four years since the first deficient auction, no matter how deficient it was, no auction is held to procure needed capacity through long term contracting. By the time the trigger is met, there is no time to address anything about the failure to meet reliability standards for the Delivery Year for the first deficient auction. At that point, PJM's proposal only calls for a Commission filing, which PJM states will be acted on in four months, followed by a bid period that stays open for six months. Thus, it would be almost another year before PJM

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119 *Id.* at Section 16.4.d).

120 RPM Base Residual Auctions would be held in May of each years.

selected winning bidders and new capacity could start the process of coming on line, which may take years for construction of a new unit. At this point in the process, the system would have been deficient for one year and within months of beginning of second deficient Delivery Year. Inexplicably, PJM prohibits Demand Resources from participating in the backstop auction.[121] By the time PJM proposes to hold the backstop auction, it may well be that a demand resource is the only type that can be online immediately. Yet, only supply resources are allowed to bid in the auction.

PJM's proposal potentially allows for all four of the Delivery Years for which the Base Residual Auction was deficient occur with no new capacity actually added to the system through this backstop mechanism. This is an unacceptable level of deficiency to allow in the system before holding an auction to see if the problem is that investors require more revenue certainty than the one year of revenue commitment for generators offered by RPM. It is also contrary to PJM's stated concerns that drive it to propose a system with a forward commitment. PJM cites the risk of insufficiency if a unit retires, despite the Reliability Must Run compensation that can be provided through the PJM tariff, on short notice.[122] And, PJM describes the difficulties it perceives in doing system planning without knowing all the resources that will serve the load in future years. Yet, the Reliability Backstop mechanism it proposes allows the system to get well beyond the point where the deficiency can be addressed without triggering a solution. This failure to act allows for the same type of capacity inadequacy that is a possibility with a generator retiring despite RMR compensation and also would eliminate the

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[121] *See* Proposed Tariff Attachment Y, Section 16.4.b, which requires that Sell Offers in the Backstop Auction be from a "Generation Capacity Resources" and specify "the megawatts of Unforced Capacity to be provided by such resource . . [and] the specific location of the proposed plant."

[122] Herling Affidavit at 8.

possibility that the full set of generation of resources is known for planning purposes. Thus, the RPM model proposed by PJM, with this untested and unduly delayed auction mechanism as a reliability backstop, is unjust and unreasonable and should be rejected outright.

VII. To The Extent The Commission Determines That Portions Of PJM's Current Capacity Construct Is Unjust And Unreasonable, There Are Targeted Solutions That Would Be Just And Reasonable.

There are better, more efficient ways to address the perceived deficiencies in the current construct. Contrary to PJM's claims, RPM will result in higher costs because it would not create market efficiencies that would benefit consumers. The CCR worked together in an attempt to offer such a targeted market-oriented approach in developing the EITCC.

For consumers, the RPM is an unacceptable approach for maintaining reliability for customers. It will lead to high prices and does not provide reasonable assurances of attracting capital necessary to maintain reliability. There are both short-term and long-term approaches to addressing capacity adequacy. A properly structured local capacity requirement – one that reflects enduring rather than transitory scarcity – may provide price signals that attract generation developers within the context of a capacity adequacy model based on a single year commitment. The CCR observes that the EITCC model, described below, offers the sort of valid price signal without being compromised by the non-market pricing inherent in the RPM, and encourage the Commission to accept this approach. However, should the Commission determine that a pure market approach is insufficient to maintain resource adequacy, the long-term commitment model described below as an alternative may provide an appropriate alternative.

A. <u>If the Commission is persuaded that the PJM capacity construct needs an incremental improvement to provide capacity revenues that vary by location, then the solution is EITCC.</u>

The Capacity Model Modification Working Group was created in March 2005 by the PJM Electricity Markets Committee to consider alternatives to the RPM. The Enhanced Integrated Transmission and Capacity Construct ("EITCC") model, discussed in more detail in Tab B, was proposed to that Working Group as an alternative that can achieve long-term reliability through incremental changes to PJM's existing capacity construct. The EITCC principally relies on markets in order to secure needed capacity.

1. This model has three fundamental parts:

a. <u>Voluntary commitments</u>

Load may acquire required capacity throughout the three years prior to a planning year. To provide an appropriate incentive for compliance with capacity requirements, stringent penalties are assessed to any load serving entity that fails to secure its requirements prior to the planning year. Load serving entities may acquire capacity either through bilateral contracts or through regular, PJM-administered capacity auctions.

b. <u>Locational capacity requirements</u>

In areas with limited local resources and limited transmission transfer capability, an appropriate portion of capacity must be purchased from within the designated area. Thus, unless generation scarcity is transitory pending construction of new transmission resources, prices will rise and signal opportunity to generation developers.

c. Enhanced transmission planning

Modification to PJM's Regional Transmission Expansion Plan are made as an integral part of the capacity model. These changes should result in transmission construction that avoids future deliverability problems such as those identified in New Jersey.

The specific enhancements are:

- make planning more sensitive to the risks that generation plants will retire;
- incorporate longer lead times needed for major transmission system upgrades;
- be more comprehensive to consistently address local issues between a transmission owner and an LSE; and
- integrated currently unconnected planning functions related to reliability, operations and congestion relief.

The EITCC does not include a demand curve. The EITCC designers found that, given the incremental changes embodied in EITCC, a demand curve results in substantial capacity price increases without significantly improving reliability.

2. Response to Criticisms of the EITCC Model

PJM asserts that the EITCC construct fails to provide forward price signals.[123] This is not the case. The clearing prices from voluntary forward auctions signal market-participants' expectations regarding the future value of capacity, both locally and in the common market. EITCC facilitates forward price signals and provides price transparency through quarterly, voluntary Planning Year ("PY") auctions for both common and local capacity credits ranging from one to four years forward. Thus,

123 Transmittal Letter at p. 22-23.

capacity prices will be revealed over the entire four years before those resources must be acquired. Clearing prices result from mutually agreeable prices set by willing buyers and willing sellers and not through an administrative price-setting mechanism, such as a demand curve.

In addition to the voluntary auction, a mandatory Final Clearing Auction ("FCA") is cleared two months prior to the start of the PY. The FCA is intended to be the final matching of buyers and sellers for their respective common and local obligations. Those short must offer to buy their full short volume at the deficiency rate (which is set at a premium to the net cost of new entry for a combustion turbine plant). The intent of the timing is to follow the last state default provider auction so, to the extent practical, a responsible load-serving entity ("LSE") has been established for all load. The common and local FCA clearing prices are also the transfer price for load shifts during the PY.

Because most market participants manage their obligations over long planning horizons, as evidenced by the fact that only 1% of total market volume clears in daily capacity markets today, the FCA would likely only see a relatively small volume. While the CCR considers the must-buy price to be sufficiently inspirational to allow the market to clear, the EITCC proposal explicitly calls for revisiting the deficiency rate if the market does not clear or if there appears to be inadequate investment levels.

Criticism that local areas under the EITCC model are too large ignores how improving the transmission planning process could reduce the need for such areas. These criticisms also do not consider EITCC's Local Reliability Auction ("LRA") used in ultra-granular areas if a problem persists. Finally, this criticism fails to consider how longer retirement notification lead-time could assist in solving local reliability concerns.

PJM's criticisms of EITCC that the model unduly relies on Reliability Must Run ("RMR") contracts is unfounded. While Reliability Must Run ("RMR") contracts may be an appropriate interim component of a long-term transmission solution, EITCC does not unduly rely on RMRs. EITCC addresses local area issues at two levels.

First, EITCC adds LMAs for the two local areas of Eastern MAAC and Southwestern MAAC. EITCC's LMAs, which are broader and more stable than the local areas in RPM, allow for a market-oriented result in contrast to RPM. This results in a more liquid tradable commodity and allows for greater supplier diversity. Within these LMAs, EITCC intends for transmission planning to maintain deliverability within the area by taking into account existing and new resource response.

Second, for a more granular solution, EITCC deals with small area problems via a competitive procurement auction for solutions that can either be short or long-term. Every year, a Local Reliability Assessment ("LRA") is performed on a two-year prospective basis to the smallest study areas to identify narrow problems in a timely manner. As further detailed in the EITCC proposal, any bilateral transactions through this competitive procurement auction initiated from an LRA are incorporated into the surrounding market in such a way so as not to interfere with the balance of the capacity market.

B. If The Commission Is Persuaded By PJM's Arguments That Short-Term Markets For Capacity Are Not Sufficient To Maintain Reliability, Then The Solution Is A System That Directly Achieves Long-Term Contracts For Capacity.

PJM asserts that the short-term nature of the current capacity construct is incompatible with maintaining reliability.[124] This is so, PJM argues, because the nature of development and financing of new capacity and PJM's needs for planning the system require that "the PJM region return to a longer term forward capacity obligation to commit generation for future years."[125] Unfortunately, as discussed extensively above, RPM fails to address these perceived core deficiencies. In fact, the level of certainty that PJM insists upon may only be achievable through a commitment period that is longer than one year.

PJM has implied that RPM achieves long term commitment from generation, combined with a corresponding revenue commitment from load.[126] Unfortunately, PJM's notion of a long-term commitment fails by confusing its four year forward requirement, with only a one year commitment, with a true long-term commitment. Simply, RPM only demands a one-year commitment from generators and only guarantees revenue for one year. Under RPM, each year beyond the target planning year is an unknown. Developers must commit to supply capacity from proposed units based on only a one year revenue stream.

Also, PJM talks at great length about the need for firm capacity commitments for future years as necessary information for planning.[127] But RPM does

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124 Transmittal Letter at p. 9.
125 Ott Affidavit, p. 15.
126 Transmittal Letter at p. 76.
127 Transmittal Letter at p. 81; Herling Affidavit at p. 7 et seq.

not even provide that information for all five years of the current planning horizon and gives no information for years in an expanded planning horizon.

PJM has correctly identified the unavoidable tension between certainty in planning and risk markets that is manifested in the PJM bulk power system. The most reliable system is a completely regulated system; the least reliable system is a pure market system. The challenge is to combine reliability and markets in a way that achieves an economically efficient and affordable system for providing electricity service. One middle ground approach is to develop a short-term market system that provides a one-year commitment that will encourage voluntary long-term commitments through bilateral contracts between load and supply. Another middle ground approach is to extend the commitment period to several years through an auction that explicitly purchases a long-term supply commitment to ensure reliability.

There are many ways that such a procurement process could be structured. Auction rules would need to optimize the lowest prices against the longest commitments that are offered. It might be prudent to spread out the procurement so that not all the capacity required for a given planning year is purchased at one time. One example is a model in which procurement might be accomplished on a rolling basis where long-term commitments of capacity are procured for a portion of the load and total requirements are provided by the sum of a series of overlapping, long-term commitments.[128] Any local capacity requirements would be established through rolling procurement combined with a

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[128] As the rolling procurement plays out, reliability requirements are met with long-term capacity commitments and PJM has the forward information it needs for planning. Instead of establishing a "price signal" only one year at a time and hoping that it will satisfy the requirements of generation developers, this system will actually get needed capacity built and retain needed capacity.

planning process where the amount and contract term of local capacity procured would be tailored to the needs of the system.

C. Under any model, the notification period for generation retirement should be increased from 90 days.

Assuming RPM's four-year forced clearing might offer greater planning certainty over the status quo, the additional information and certainty has a very high price. Those paying the bill question if the incremental information and certainty gain is worth the tremendous cost and impact on progress towards market-oriented solutions. As evidenced by numerous comments during the technical conference, a great deal of the problem appears to originate from generators having as little as a 90-day notice obligation to announce a retirement. See PJM Interconnection, LLC, 110 FERC ¶ 61,053 at PP 136-137 (2005).

The CCR believes that it would be productive to explore alternative solutions for the exception rather than push the entire market to four years. At the most basic level, a longer retirement lead-time could be considered as a reasonable requirement. A product defined by an organized market has deadlines to participate and given the nature of the resource adequacy product a more substantial advance declaration may be suitable. This could be considered similar to PJM's requirement that energy bid in the day-ahead market must be submitted by noon the day prior. With a similar logic, to provide greater certainty to PJM for existing capacity resources, the retirement notice lead time could be changed from 90-days to 12 months. Certainly, this is not the only approach, but it may be worthwhile to focus efforts on the exception rather than the system in total.[129]

[129] In this regard, the CCR note that the issue of an incentive as additional encouragement to provide a longer notice period is being addressed in the stakeholder process.

VIII. PJM's stakeholder process was protracted but consideration of stakeholder concerns about the substance of the RPM were severely limited

The CCR takes issue with PJM's representation that the stakeholder process around the RPM was open and inclusive. PJM maintains[130] that the model as filed represents changes from a number of stakeholders. However, substantive changes advocated by end-use customers, cooperatives, municipal utilities and others were universally rejected. The only change to PJM's proposal made in light of stakeholder concerns was a modification of the demand curve. In view of this disagreement regarding the process through which the RPM was developed, the CCR finds it necessary to briefly outline the profound defects in the stakeholder process. Several points are highlighted below:

- Opportunities for substantive debate were limited to a few months in the 14 month process from introduction of the model to filing of the RPM.
- PJM seeks to further exclude the stakeholders from this and future filing by shifting the capacity adequacy system from the Operating Agreement to the Tariff.
- PJM consistently rejected all stakeholder appeals for substantive modifications to the RPM.
- The large majority of voting PJM members repeatedly rejected the RPM.
- The large proportion of those supporting the RPM will benefit from it monetarily as they own generation either directly or through affiliates.

Contrary to PJM's portrayal of events, a broad spectrum of stakeholders comprised a substantial majority rejecting RPM while the bulk of RPM's supporters have a substantial, direct financial interest in seeing RPM implemented.

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130 Transmittal letter p.13.

After the publication of a whitepaper in June 2004, the RPM stakeholder process began in earnest in August 2004, involving at least two stakeholder meetings a month through February 2005. PJM initially proposed to file the RPM by the end of 2004 but deferred this as the RPM continued to evolve. Prior to the January 2005 Members Committee meeting, the stakeholder working group process consisted of PJM presentations on the ongoing changes to the RPM. Thus, from June through December 2004 the schedule and amount of material to be covered often resulted in many questions not being addressed. As a rule, PJM requested that stakeholders focus on the evolving components of RPM and defer questions or concerns about the overall direction of RPM, its impacts and its appropriateness until the proposal was fully developed. As a result, it was not until late December 2004 and early January 2005 that a complete draft of PJM's proposal with simulated auction results was available for stakeholder review.

In other words, the first opportunity for open debate on the RPM occurred in mid-December. In fact, there was never an opportunity to discuss any alternatives to PJM's proposal prior to the January 2005 Members Committee meeting. Nonetheless, PJM proceeded with its sense of urgency, insisting that its RPM proposal must be filed with the Commission in early March 2005 in order to provide sufficient lead-time for implementation prior to the beginning of the planning year on June 1, 2006. PJM's self-imposed timeline led to incomplete information, unanswered questions and a process designed to produce a filing of the RPM rather than a model that had been seriously considered through the stakeholder process.

After failing to achieve even a majority vote to proceed with an RPM filing at the Members Committee meeting in January 2005, PJM convened a special two-day stakeholder conference for February 17-18, 2005. The discussion revealed serious stakeholder concerns regarding the RPM. Of particular concern were PJM's simulation results showing substantial cost increases in the first four years of RPM implementation in all regions of the PJM footprint. The assumptions underlying the demand curve, and even the need for any demand curve, were sharply questioned. The necessity of a long forward commitment was rejected. The inability of demand resources to discipline capacity prices under the RPM was strongly emphasized. Many participants urged that alternatives to RPM be considered.[131]

Over the objections from PJM, the meeting facilitator at the February meeting agreed to a straw vote on a request that the Electricity Markets Committee ("EMC") sponsor a Working Group to examine alternatives to RPM. Approximately sixty percent of those voting supported the request and the Working Group began its deliberations in March 2005. At the subsequent Members Committee meeting on March 17, 2005, over two thirds of the members voted to reject RPM. Thus, it was almost nine months after the RPM was unveiled that alternatives were first examined in detail. Once those details became evident, a supermajority or close to a supermajority of members repeatedly rejected the RPM model.

PJM asserts erroneously[132] that opposition to RPM came primarily from load interests. In fact, as the vote totals in each stakeholder meeting from January through March of 2005 demonstrates, about two-thirds of members opposed the RPM. End-use customers comprise one of the five stakeholders sectors, accounting for 20% of the weighted vote. The other 40% to 47% of member votes opposing RPM came from

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131 See Stakeholder Comments and Panel Comments, http://www.pjm.com/committees/working-groups/pjmramwg/pjmramwg.html.

132 Transmittal Letter p. 50.

other sectors. The conclusion must be that there was opposition to RPM from far more than end-use customers. Looking at the reverse of PJM's perspective is also instructive and it becomes clear that those consistently supporting the RPM are generation owners and transmission owners who have extensive affiliated generation. As the analysis of potential costs indicates above, these are precisely the interests who will benefit substantially from the implementation of the RPM.

In the final analysis, the meetings in February and March comprised the last substantive, stakeholder discussion of the RPM. Summaries of alternative models were presented to the PJM Board but there was no serious opportunity for evaluation or discussion. Two RPM alternatives were developed and proposed but RPM itself was never seriously on the table. Following the Commission's Technical Conference on June 16, there was no broad stakeholder discussion to examine changes to the RPM or to further examine alternatives.

The CCR is second to none in their strong support of the PJM stakeholder process. PJM's extraordinary efforts to achieve stakeholder consensus on previous issues has paid high dividends in its success as an RTO and the efficiency of is competitive marketplace. It is essential that PJM foster opportunities for meaningful stakeholder interaction as the competitive marketplace continues to evolve. Regrettably, the stakeholder process for RPM was atypical of PJM's previous record of superior facilitation.

Contrary to PJM's assertion, much progress has been made in the capacity construct debate. Indeed, it is a testament to PJM's previous track record of unbiased independence and charge to maintain reliability that has enabled load interests to recognize the potential value of a capacity market with a local component and longer commitment requirements. This realization, however, was only possible via PJM's leadership to provide the necessary legitimacy to the previous speculative debates hosted by those who would gain the most by artificially increasing their revenues via non-market means. The RPM stakeholder process is the only forum where potential violations of local transmission reliability criteria have been raised.

That being said, over the past five years, the PJM stakeholders have not worked constructively to develop new capacity markets. No prior stakeholder effort was focused or solving actual reliability problems.

IX. Conclusion

PJM has proposed to replace its current capacity construct with a highly integrated set of changes to its Tariff, the Operating Agreement, and the Reliability Agreements. The RPM proposal was repeatedly rejected by the PJM stakeholders. Therefore, PJM has the burden under Section 206 of the FPA to show that the current construct is unjust and unreasonable. As demonstrated above, PJM has not met that burden. PJM has identified dysfunctions in the current construct that can be dealt with through targeted solutions. The creation of an entirely new approach to resource adequacy is a response that is disproportionate to the problems at hand. Even if the Commission finds that there are aspects of the current capacity construct that are unjust and reasonable, it has been demonstrated above that PJM's proposal must be rejected because it inflicts too much harm on consumers to be just and reasonable. These are ample reasons for the Commission to reject the RPM and order PJM to fully develop EITCC in concert with its stakeholders and within a specified time frame.

The Commission should reject PJM's filing outright as improperly filed. At the least, the foregoing has raised disputes of fact as to whether the Hobbs and Ott analyses provide useful information on whether RPM would produce resource adequacy at reasonable costs.

If not rejected outright, there are significant questions as to whether demand response can effectively participate under RPM and whether the reliability backstop provisions are adequate. Thus, if the filing is not rejected, there are sufficient disputes of material fact raised in this protest to require a full evidentiary hearing.

If not rejected outright, and in order to provide certainty to the markets, and allow for sufficient time to thoroughly examine the critical issue of how to ensure resource adequacy at just and reasonable prices, the Commission should order that the any changes will be prospective only and, in any event, will not be implemented prior to the planning year that begins June 1, 2007. PJM has made a suggestion to bifurcate review of this filing by requesting an order approving the "key features" of RPM without a hearing and the convening some type of technical conference to discuss "...final just and reasonable parameters of the VRR curve used to clear the RPM auctions."[133] The disputes raised in this protest go to whether the "key features" of RPM will ensure reliability at just and reasonable prices. Discussion on how to draw the VRR curve cannot cure the defects discussed herein. PJM's suggestion would prevent the Commission from having a sufficient record to judge the issues raised in this protest and should be rejected. If the Commission accepts this case as properly filed under Section 205, PJM's filing should be suspended for the maximum period allowable.

WHEREFORE, the Commission should:

a) reject PJM's filing as improperly filed;

b) if not rejected as improperly filed, hold PJM to the Section 206 burden of proof and reject the filing as failing to satisfy the Section 206 burden of proof;

c) if not reject outright, order that any changes will be prospective only and in any event will not be implement prior to the planning year that begins June 1, 2007;

d) reject PJM's request that the key features of RPM will be approved in the absence of a hearing;

e) and if not rejected outright and not made effective prospectively or no sooner than June 1, 2007, suspend for the maximum statutory period; and

133 Transmittal Letter at 2.

f) require that PJM return to the stakeholder process to develop consensus on the EITCC proposal to address any concerns with the existing capacity market design that the Commission finds have merit.

Respectfully Submitted,

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