123 FERC ¶ 61,051
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Joseph T. Kelliher, Chairman;
Suedeen G. Kelly, Marc Spitzer,
Philip D. Moeller, and Jon Wellinghoff.

PJM Interconnection, L.L.C. Docket Nos. ER06-1474-002
ER06-1474-004

ORDER ON REHEARING AND COMPLIANCE

(Issued April 17, 2008)

1. On October 9, 2007, PJM Interconnection, L.L.C. (PJM) submitted a compliance filing in response to the Commission's June 11 Order.[1] That order accepted in part and rejected in part PJM's earlier compliance filing that revised its proposed regional economic transmission planning process (RTEP) and operating agreement. In this order, the Commission grants in part and denies in part requests for rehearing, and accepts in part and rejects in part PJM's second compliance filing.

I. **Background**

2. The background of this case is described in detail in the June 11 Order. Briefly, the Commission conditionally accepted PJM's proposal to replace the unhedgeable congestion approach to planning for "economic" transmission expansion[2] with a process

[1] *PJM Interconnection, L.L.C.*, 119 FERC ¶ 61,265 (2007) (June 11 Order).

[2] PJM divides transmission expansions into two categories: reliability and economic. Reliability expansions are those needed to ensure that load can be met reliably. Economic expansions (also called "market efficiency" expansions) are those that will reduce the costs of meeting load but are not needed to meet load reliably.

that would have considered seven congestion metrics.[3] The Commission conditioned its acceptance of the filing on PJM making a compliance filing explaining how it would weigh, consider, and/or combine the congestion metrics. The Commission also directed PJM to explain how generators and demand response providers would be included in the economic planning process.

3. The June 11 Order accepted PJM's compliance filing on participation of demand response, generation, and advanced technologies in the planning process, but rejected its proposed metrics. Instead, we directed PJM to file a formulaic approach to choosing proposed economic projects, and to describe exactly how any metrics would be calculated, weighed, considered and combined. In doing so, we referenced the so-called "weighted gain-no loss metric" used by Midwest Independent Transmission System Operator, Inc. (Midwest ISO) as a possible approach. That metric calculates the anticipated annual benefits of a proposed project to customers using two present value metrics: (1) the production cost benefit (weighted at 70 percent); and (2) the locational marginal price (LMP) energy cost benefit (weighted at 30 percent).

4. The June 11 Order noted that a formula may not identify all economic projects that would be beneficial, and so certain projects that failed under the formula should, nevertheless, be considered under certain circumstances. Accordingly, we stated that if PJM wants to include projects that fail the "bright-line" formula, it could propose a tariff provision that would permit such projects on a case-by-case basis.

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[3] *PJM Interconnection, L.L.C.,* 117 FERC ¶ 61,218 (2006) (November 21 Order). PJM's proposed metrics included: (i) total production costs (fuel costs and variable O&M) associated with changes in the PJM generation dispatch pattern allowed by the proposed upgrades' alleviation of transmission bottlenecks; (ii) total load payments (load times load Locational Marginal Price) assuming the customers purchase all energy needs from the PJM spot market; (iii) total generator revenue (generator MW times generator Locational Marginal Price); (iv) zonal load payments (zonal load MW times zonal Locational Marginal Price); (v) zonal Financial Transmission Right credits (as measured using currently allocated Auction Revenue Rights plus additional Auction Revenue Rights made available by the proposed acceleration of a planned reliability-based enhancement or expansion or new economic based enhancement or expansion); (vi) total Transmission System losses; and (vii) total capacity payments under the Reliability Pricing Model (RPM).

5. Finally, the June 11 Order directed PJM to provide more detail on how it will consider demand response and generation availability trends in subsections 1.5.7(k)(vii)[4] and (viii)[5] of Schedule 6 of the Operating Agreement.

II. PJM Compliance Filing

6. PJM states that it will now use a benefit/cost ratio to determine whether an economic-based enhancement or expansion will be included in the RTEP. To be included, a project's benefit/cost ratio must meet a threshold of at least 1.25 to one. PJM states that the benefit/cost ratio will be calculated by dividing the present value of the total benefit for each of the first 15 years of the life of the project by the present value of the total cost for each of its first 15 years.[6]

7. PJM states that assumptions for determining the present value of the benefits and costs (e.g., discount rate and annual revenue requirement) will be approved by the PJM Board each year for the economic planning process. It argues that the threshold benefit/cost ratio of 1.25 to one appropriately hedges against the uncertainty of estimating benefits in the future, while not being so restrictive as to overly limit the economic-based enhancements or expansions that would be eligible for inclusion in RTEP. It notes that its proposed threshold, which is constant, differs from Midwest ISO's, which is based on a sliding scale and adjusts depending on the in-service date of the project. PJM argues that this difference (which may have the effect of including long-term projects that Midwest ISO's sliding-scale approach might exclude) is justified given the need for significant new transmission construction in the PJM region based on long term needs such as those identified in the Department of Energy's recent National Interest Electric Transmission corridor designation in the PJM region.

8. To calculate the elements in the benefit/cost ratio, PJM proposes a benefit component as the sum of two metrics: the energy market benefit and the reliability pricing model benefit. PJM argues that by including these two metrics, the formula will

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[4] Subsection 1.5.7(k)(vii) provides, with regard to demand response, that PJM will consider the "Expected level of demand response over at least the ensuing ten years based on analyses that consider historic levels of demand response, expected demand response growth trends, impact of capacity prices, current and emerging technologies, and sensitivity analyses regarding the foregoing."

[5] Subsection 1.5.7(k)(viii) provides, with regard to generation, that PJM will consider the "Expected levels of potential new generation and generation retirements over at least the ensuing ten years."

[6] Operating Agreement, Schedule 6, § 1.5.7(d).

account for the benefits to customers from reductions in both energy prices and capacity prices as a result of the proposed project.

9. Thus, PJM proposes to calculate the "Energy Market Benefit" as:

> Energy Market Benefit = [.70] * [Change in Total Energy Production Cost]
>
> + [.30] * [Change in Load Energy Payment]

10. PJM explains that "Change in Total Energy Production Cost" in the formula equals the difference in estimated total-annual-fuel costs, variable operating and maintenance (O&M) costs, and emissions costs of the dispatched resources in the PJM region with and without the enhancement or expansion.

11. It further explains that "Change in Load Energy Payment" is the difference between the annual sum of the hourly-estimated zonal-load megawatts for each PJM transmission zone multiplied by the hourly-estimated zonal LMP for each PJM transmission zone without and with the economic-based enhancement or expansion. To determine "Change in Load Energy Payment" for projects, which have costs allocated through a postage-stamp methodology (i.e., facilities at or above 500 kV), PJM states that the load-energy payment in each and every PJM transmission zone will be considered whether there is an increase or decrease in the load-energy payment in the transmission zone.

12. PJM states, however, that for projects the cost of which will be allocated using a flow-based or distribution factor methodology (e.g., below 500 kV facilities), only the load-energy payment in the PJM transmission zones that show a decrease will be considered in determining the change in load-energy payments. It argues that the difference in treatment is designed to take account of benefits to those customers that will pay for the economic-based enhancements or expansions that address local congestion.

13. Next, PJM proposes to calculate the "Reliability Pricing Model Benefit (RPM)" as:

> RPM Benefit = [.70] * [Change in Total System Capacity Cost] + [.30] * [Change in Load Capacity Payment]

14. PJM explains that "Change in Total System Capacity Cost" is the difference between the sum of the megawatts that are estimated to be cleared in the base residual auction under PJM's RPM capacity construct times the prices that are estimated to be contained in the offers for each such cleared megawatt (times the number of days in the study year) with and without the economic-based enhancement or expansion.

15. It further explains that "Change in Load Capacity Payment" is the sum of the estimated zonal-load megawatts in each PJM transmission zone, times the estimated final zonal-capacity prices (payments paid by load in each transmission zone) for capacity under the reliability pricing model (times the number of days in the study year), without and with the economic-based enhancement or expansion. Similar to "Change in Energy Load Payment," "Change in Load Capacity Payment" for projects the costs of which will be assigned based on postage stamp rate (i.e., facilities at or above 500 kV), the load-capacity payment in each and every PJM transmission zone will be considered; for projects, the cost of which will be allocated using a flow-based or distribution-factor methodology (e.g. below 500 kV facilities), only the load-capacity payments in the PJM transmission zones that show a decrease will be considered.

16. The formulas for both the "Energy Market Benefit" and "RPM Benefit" weight the change in production costs at 70 percent and the change in load payment at 30 percent. PJM argues that the proposed weighting of production cost and load payment benefits is consistent with the Midwest ISO approach that the Commission previously has determined to be reasonable. It asserts that the change in production costs approximates the societal good associated with an economic-based enhancement or expansion by measuring the overall reduction in the cost of producing electricity in the PJM region. It argues that the reduction in production costs is a standard measure of the economic benefits of an expansion or enhancement, thus warranting significant weight when determining the benefits of an economic-based upgrade. It states that the 30 percent load-payment metric provides within the formula a reasonable measure of the direct impact on load.

17. Turning to the cost side of the benefits/cost ratio, PJM proposes to use the revenue requirement of the economic-based enhancement or expansion to calculate "Total Enhancement Cost." PJM states that, consistent with the Midwest ISO order, the benefits and costs will be considered over the same period (for each of the first 15 years of the life of the expansion or enhancement).

18. PJM also addresses the issue of keeping market participants informed by proposing to calculate and post on its website changes in the following metrics on a zonal and system wide basis: (1) total energy production costs (fuel costs, variable O&M costs and emissions costs); (2) total load energy payments (zonal load MW times zonal load LMP); (3) total generator revenue from energy production (generator MW times generator LMP); (4) Financial Transmission Right credits (as measured using currently allocated auction revenue rights plus additional auction revenue rights made available by the proposed acceleration or modification of a planned reliability-based enhancement or expansion or new economic-based enhancement or expansion); (5) marginal loss surplus credit; and (6) total capacity costs and load capacity payments under its reliability pricing model.

19. To address concerns over how PJM will consider generation and demand-response trends, it now specifies that, in the market efficiency analysis, it will include in its assumptions expected levels of potential new generation and generation retirements over at least the ensuing 15 years (rather than the ensuing ten years) based on analyses that consider generation trends based on existing generation on the system, generation in the PJM interconnection queues, and capacity resource clearing prices under Attachment DD of the PJM Tariff (reliability pricing model).[7] PJM further states that it will evaluate demand-response trends over at least the ensuing 15 years. If the PJM reserve requirement is not met in any of its future-year market-efficiency analyses, PJM states that it will model adequate future generation based on the type and location of generation in existing PJM interconnection queues.

III. Procedural Matters

20. Notice of PJM's compliance filing was published in the *Federal Register*, 72 Fed. Reg. 59,281 (2007), with protests and interventions due on or before October 30, 2007. The Long Island Power Authority and its operating subsidiary LIPA (collectively LIPA), Old Dominion Electric Cooperative (Old Dominion), National Grid USA (National Grid) and Strategic Transmission, LLC (Strategic) filed comments. Dayton Power and Light Company (Dayton), Rockland Electric Company (Rockland), PSEG Companies (PSEG)[8] and Exelon Corporation (Exelon) filed protests. The American Electric Power Service Corporation filed a timely motion to intervene. Dominion Resources Services, Inc. filed a motion to intervene out of time. PJM filed an answer to the protests. Rockland filed a motion for leave to reply and reply to answer of PJM.

21. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2007), the timely, unopposed motion to intervene serves to make the entity that filed it a party to Docket No. ER06-1474-004. Given its interest in the proceeding, the early stage of the proceeding, and the absence of undue prejudice or delay, we will grant Dominion's untimely motion to intervene in Docket No. ER06-1474-004. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2), prohibits an answer to a protest unless otherwise ordered by the decisional authority. We will therefore reject PJM's and Rockland's answers.

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[7] Operating Agreement, Schedule 6, § 1.5.7(k)(viii).

[8] PSEG Companies are comprised of: Public Service Electric and Gas Company (PSE&G); PSEG Power LLC (PSEG Power); and PSEG Energy Resources and Trade LLC (PSEG ER&T).

IV. Discussion

A. Rehearing Requests

22. In Docket No. ER06-1474-002, FirstEnergy, PSEG and the New Jersey Commission requested rehearing and clarification of the November 21 Order. Specifically, these parties raised issues pertaining to the cost/benefit analysis performed by PJM, congestion metrics, forecasting techniques, and other issues raised in the November 21 Order. In the June 11 Order, the Commission deferred ruling on these requests since the November 21 Order required PJM to make a further compliance filing. Now that PJM has made its second compliance filing, we will address the rehearing requests.

1. Discrimination in favor of Rate-Based Solutions

a. Rehearing Requests

23. In its rehearing request, PSEG reiterates the arguments raised in its earlier protest, stating that changes to the economic planning process are unduly discriminatory against competitive generation, merchant transmission and demand response, and instead favor rate-based solutions. PSEG asserts that PJM submitted no empirical or analytical evidence to show that the proposal is not unduly discriminatory, and further failed to explain the impacts of rate-based transmission on competitive generation, demand response or the continued development of merchant transmission, and that the Commission erred in accepting PJM's unsupported claims.

24. The New Jersey Commission agrees, and states that we erred in arguing that market and rate-based solutions are on par because PJM's proposal allows rate-based solutions to be considered immediately as opposed to waiting a year after congestion is identified. The New Jersey Commission states that even if PJM's proposal treated rate-based and market-based solutions equally, rate-based transmission expansions would still be favored because the developers of rate-based and market-based projects do not bear equal risks. Once PJM has identified a rate-based transmission expansion where risk will be socialized, it is difficult for a market-based project developer, who bears his own risk, to displace it. It rejects the notion that market participants will be able to compete more effectively now because PJM's proposal will allow market participants to construct additional economic-based enhancements or expansions to relieve an economic constraint. The New Jersey Commission argues that market participants could always submit these proposals to PJM and they could do so without the disadvantage of competing with regulated solutions. Ultimately, the New Jersey Commission argues that market-based projects should not be undermined because they can deliver equal or better reductions in congestion with less risk to electricity customers, lower cost, and greater reliability.

25. The New Jersey Commission further argues that our previous orders on PJM's RTEP only required PJM to identify expansions that were needed to support competition as well as reliability needs, and did not address at all the economic planning now proposed by PJM.

b. Commission Determination

26. We agree with the New Jersey Commission and PSEG that market-based solutions should not be undermined and that the PJM proposal does not take away from market-based solutions stepping forward. The PJM process, however, does provide a backstop in the event market solutions do not come forward and in that process, i.e., the economic planning at issue here, PJM evaluates all projects (market and regulated). PJM's proposal to revise the process for selecting economic projects does not mean that the focus has shifted from supporting competition. As we stated on numerous occasions, without a process for identifying economic transmission, PJM's customers located in load pockets and separated from the rest of the system by congested transmission bottlenecks, will have few opportunities to access alternative resources that have lower prices for electricity. PJM has an obligation, established in Order No. 2000,[9] to create a planning process that gives "full consideration to all market perspectives and identifies expansions that are critically needed to support competition as well as reliability needs."[10] PJM is making revisions to its economic planning protocols because its prior methodology did not produce the expected results. Despite several reliability-based projects recently approved through RTEP, there were very few economic projects. Economic projects are efficient to build to address pure congestion problems that are not always addressed by building a reliability-based project needed to meet voltage, thermal or other reliability criteria. And while merchant-transmission projects built by third parties may also relieve congestion and foster competition, they alone will not be able to address the problems faced by PJM, because of the risks associated with merchant transmission, thus limiting the number, the configuration or the size of the merchant-transmission projects. This was also recognized in our prior orders, where we directed PJM to create a planning system that would accommodate both merchant and regulated transmission projects. Thus, there is no inconsistency between our prior orders and the November 20 Order.

27. Moreover, as we stated in the June 11 Order, demand resources, generation, and merchant transmission facilities described in subsection 1.5.7(k) may qualify at any time

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[9] *Regional Transmission Organizations*, Order No. 2000, FERC Stats. & Regs. ¶ 31,089 (1999), *order on reh'g*, Order No. 2000-A, FERC Stats. & Regs. ¶ 31,092 (2000), *aff'd sub nom. Public Utility District No. 1 of Snohomish County, Washington v. FERC*, 272 F.3d 607 (D.C. Cir. 2001).

[10] *PJM Interconnection, L.L.C.*, 101 FERC ¶ 61,345, at P 20 (2002).

and PJM will incorporate them in the market efficiency assumptions whenever they are present. Qualified resources known before the first of January prior to the June presentation of the market efficiency assumptions to the PJM Board for approval will be included in the analysis. However, demand and other resources that subsequently qualify under subsection (k) will not be ignored. PJM will include them in the next RTEP analysis, as well as the annual reviews of prior plans, and, to the extent necessary, PJM will notify any entity with construction responsibility for an economic-based upgrade that the need for the upgrade may be diminished or obviated as a result of the inclusion of the qualified resource in the assumptions for the next annual market efficiency analysis or annual review of costs and benefits.

28. Contrary to PSEG's arguments, PJM's proposal does not unduly discriminate. Instead, PJM has proposed a transparent process with opportunities for market-based project developers to review and comment on all potential RTEP projects at multiple stages of conception and development.[11] PJM has committed to publishing information to give project developers the ability to identify constraints, to propose market-based solutions, and thus, to eliminate the need for economic-based transmission enhancements. Moreover, market-based solutions can be introduced at any time in the RTEP process.

29. In addition, PJM clarified that it included alternative projects in its study assumptions and relied on their availability in determining the need for economic-based upgrades. Its formulaic approach to choosing economic projects that weighs costs and benefits through a specific set of metrics (as discussed in greater detail below) provides clarity to PJM's approach to economic proposals, and therefore, will give potential investors additional certainty.

30. Finally, PJM's proposal remains consistent with the FPA because it promotes an economically efficient transmission system, and it is not unduly discriminatory. We will therefore deny PSEG's and the New Jersey Commission's requests for rehearing on this point.

2. Assumptions, Forecasts, and Metrics

a. Rehearing Requests

31. The New Jersey Commission argues that PJM should give to stakeholders and state commissions the assumptions that it uses in its forecasts and some measure of the accuracy of such forecasts. The New Jersey Commission further argues that PJM should perform sensitivity analyses around key inputs into its analyses, such as price forecasts.

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[11] *See, e.g.*, Tariff, § 1.5.7(a).

32. PSEG argues that the lack of specificity in the assumptions, estimating process, cost benefit analysis and process for considering alternative projects is too vague and thus insufficient to produce just and reasonable transmission planning. It further argues that the use of vague and undefined long-term forward price forecasts is inappropriate to justify placing rate-based economic transmission projects in the RTEP. In the alternative, it argues that the Commission should clarify that it intended that such long-term forward price forecasts include or be updated periodically to include: (1) reasonably forecasted new supply; (2) the PJM reserve requirement; and (3) forecasted demand-response.

33. FirstEnergy argues that PJM should identify and define the "standards, thresholds, tests and criteria" that will guide formation of the "assumptions" and write this information into the Tariff. It argues that if forecasting is to be included, the term of the forecast should be reduced from 15 to 5 years because long-term forecasts regarding potential future congestion are not reliable.

34. The New Jersey Commission, PSEG and FirstEnergy all take issue with the vagueness of PJM's proposed metrics.

35. PSEG argues that PJM must adequately explain how it will consider the triggers that will cause a rate based economic transmission project to be placed in the RTEP.

36. FirstEnergy, too, believes that the metrics are not adequately explained, and suggests that the Tariff should detail how PJM will weigh, consider and/or combine the metrics as part of formulating a list of projects to consider with regard to a given economic constraint.

b. Commission Determination

37. We deny the requests that PJM provide assumptions and a greater measure of specificity. In our June 11 Order, we agreed that PJM had failed to provide appropriate metrics and, therefore, required PJM to make the compliance filing that is at issue in this order. PJM has, for example, added to its Operating Agreement the specific assumptions to be used in the market efficiency analysis and any review of costs and benefits.[12] These include timely installations of qualifying transmission upgrades, the availability of generation capacity resources and the availability of demand resources. The Operating Agreement has been further modified to include the discount rate used to determine the present value of the total annual enhancement benefit and total enhancement cost and the annual revenue requirement used to determine the total enhancement cost.[13] The rehearing requests, therefore, are moot.

[12] Operating Agreement, § 1.5.6(k)(i)-(ix).

[13] Operating Agreement, § 1.5.7(a).

38. We similarly find moot the additional requests to require that PJM provide stakeholders and state commissions with additional information.

39. We will also deny rehearing on PJM's 15 year planning horizon. As discussed in greater detail below, we find that PJM's amended formula, as modified by this order, as well as its substantial stakeholder process, will reasonably offset the uncertainty inherent in determining the economic need for transmission projects that will last for decades.

40. We will, however, grant the New Jersey Commission's rehearing request to require PJM to perform sensitivity analyses around key inputs, such as price forecasts. We discuss this in the compliance section below.

3. Cost/Benefit

41. First Energy argues on rehearing that there is no test for determining which project to choose. It states that this contrasts with the "old" economic planning process, where the tariff required PJM to conduct a cost-benefit analysis for the purpose of determining whether the project's economic benefits exceeded the costs for building it. Only projects that passed this test would be approved as RTEP projects. It argues that the tariff should be amended to include language that requires that the economic benefits of the project (or the economic portion of an accelerated reliability project) exceed the costs of building it.

42. We will deny FirstEnergy's request as moot since, as discussed above, we required PJM to provide the formula and metrics in the compliance section below, and required PJM to ensure that the benefits of a proposed project exceed the costs before it can be included as part of the RTEP.

4. Cost Allocation and Opting Out

a. Rehearing Requests

43. The New Jersey Commission argues that transmission project developers should assume the risk of that project, including the risk that PJM's projections turn out to be wrong. In a related argument, it argues that transmission that has been included in the RTEP, but that subsequently becomes unnecessary based on new generation or demand response, should not be paid for by customers who did not choose to assume the risk that such transmission would become unnecessary.

44. The New Jersey Commission further argues that, while the Transmission Expansion Advisory Committee (TEAC) will serve as a forum for stakeholders to express their views on upgrades proposed by PJM, it does not provide the consumer with a right to opt-out.[14] It states that, although the consumer is most often the load-serving entity,

[14] *See* November 11 Order at P 38.

the consumers that ultimately pay for such upgrades are the end-users. It argues that consumers will not be able to voice whether an upgrade is approved when the cost allocation for the upgrade is filed with the Commission because the Commission has ruled that cost allocation proceedings are not the proper proceeding to determine whether or not an upgrade should be approved.

45. Similarly, PSEG argues against including a rate-based economic transmission project in the RTEP where the alleged beneficiaries of that project do not want that project or where the project is not the most cost-effective option. In the alternative, it argues the Commission should clarify that PJM does not have the discretion to include a rate-based economic transmission project in the RTEP where either the projected beneficiaries do not vote in favor of that specific project or a lower-cost solution is available. It also asks the Commission to clarify that a state or region can opt out of a rate-based economic transmission project and not be subject to any cost allocation for such project.

46. PSEG states that PJM must explain whether cost allocations will change if a merchant project is developed that modifies the need for, or scope of, the rate-based project. It argues that if costs are to be allocated to external parties, Schedule 6 of the PJM Operating Agreement must set forth a mechanism for such allocations.

47. Finally, PSEG, FirstEnergy and the New Jersey Commission each argue on rehearing that the proposal should include a method for the allocation of costs. Proposals range from a beneficiary pays method to an opt-out provision for certain entities.

b. <u>Commission Determination</u>

48. We do not agree with the New Jersey Commission's argument that transmission project developers should assume the risk of a project if PJM's projections turn out to be wrong. Transmission owners are building a project that PJM has determined is necessary. Since the transmission owner did not propose the transmission project, penalizing it for PJM's errors in projections or for subsequent changes in circumstances would be unfair.

49. However, we also recognize that there are risks associated with extended price forecasts that may dictate a need for a project that later may appear unjustifiable. To address this concern, as we discuss below, PJM is required to take steps to ensure that projects are justifiable in the long-term by requiring that the benefits significantly outweigh the costs, shortening the length of the planning period, and sensitivity analysis. We address the New Jersey Commission's and PSEG's request to allow end-users a right to opt out, in the compliance filing discussion below, where we address PSEG's proposition to establish voting procedures.

50. With regard to cost allocation procedures, PSEG is seeking clarification about whether cost allocations will change if a merchant project is developed that modifies the need for, or scope of, the rate-based project. We find that section 1.5.7 (f) of Schedule 6 of the Operating Agreement already satisfactorily addresses this issue. It specifies that:

> The annual review of the costs and benefits of constructing new economic-based enhancements and expansions included in the Regional Transmission Expansion Plan shall include review of changes in cost estimates of the economic-based enhancement or expansion, and changes in system conditions, including but not limited to changes in load forecasts, and anticipated Merchant Transmission Facilities, generation, and demand response…."

51. In general, cost allocations are done in accordance with Schedule 12 of the PJM tariff and are not within the scope of this filing; they are being addressed in Docket No. ER06-456, *et al*. The rehearing requests do not explain why this cost allocation issue needs to be addressed here rather than in that proceeding. Accordingly, we deny the rehearing requests. Similarly, PSEG's request to allocate the costs of new economic projects to external parties is more appropriately addressed in that ongoing proceeding.

5. Advanced Technologies

a. Rehearing Requests

52. PSEG argues that the November 21, 2006 Order erred by assuming that PJM takes responsibility for addressing new technologies, such as advanced conductors, and for comparing them to traditional technologies. It argues that advanced technologies are not considered as part of PJM's metrics for evaluating projects.

a. Commission Determination

53. We deny rehearing. Under PJM's formula, it is not required to use advanced technologies as part of its metrics.

54. Although not part of the metrics, we asked PJM in our November 20 Order "to provide additional information regarding the advanced technologies currently assessed and whether distributed generation and high efficiency transformers are among those

technologies."[15] PJM's compliance filing on this issue was accepted in the June 11 Order, in which we noted that the RTEP process is flexible enough to take future technologies into account as they plan their system over time. Within the RTEP, PJM already looks to use new conductor technologies that will provide for the greatest utilization of limited transmission corridors. PJM also is implementing high voltage direct current technology and variable frequency transformers through proposals of merchant-transmission providers, and Static Var Compensation devices that PJM is planning and directing through the RTEP.

B. <u>PJM's Second Compliance Filing</u>

1. <u>Production Cost and Load Payment Metrics</u>

55. In the June 11 Order, we directed PJM to file a formulaic approach to choosing proposed economic projects, and to describe exactly how any metrics would be calculated, weighed, considered and combined.

a. <u>Protests</u>

56. Several parties object to PJM's proposed weighting of production costs and load payment. Dayton, for example, argues that the formula inappropriately dilutes the weight given to the costs and benefits experienced by load in favor of a formula that is heavily weighted toward forecasted production cost changes. PSEG argues that net change in load payment should be the only benefit metric in PJM because to determine the net social impact of an economic transmission project, one must look at the impact on the parties paying the transmission costs. It argues that transmission costs in PJM are paid by load.

57. PSEG states that if a weighted ratio is adopted, the weights should be reversed so that a change in load payment is more heavily weighted than a change in total energy production cost. It argues that the current ratio reflects the reality in the Midwest ISO where customers have limited exposure to changes in LMP. PSEG argues that this is not the case in PJM where most consumers are exposed to competitive energy market prices and changes in LMP. Accordingly, PSEG argues, it makes more sense to look to a

[15] November 21 Order at P 44. In accordance with our Order, PJM explained in its compliance filing in Docket No. ER06-1474-003 that, within the RTEP, it uses new conductor technologies that provide the greatest use of limited transmission corridors. PJM stated that it is implementing high voltage direct current technology and variable frequency transformers through proposals of merchant transmission providers, and static var compensation devices through the RTEP. PJM also stated that it will look for further opportunities to enhance the reliability and economic performance of the grid through innovative analysis methodologies and approaches.

change in load payment more than a change in production cost in PJM as the actual benefit that would result from the construction of economic transmission.

58. National Grid also opposes the weighting proposal, arguing that PJM's load distribution is nearly the exact inverse of Midwest ISO. Similar to PSEG, National Grid explains that production costs are an appropriate measure of the economic benefits of transmission upgrades where a generator is compensated through cost-based rates rather than market prices. National Grid estimates that at least 64 percent of the load in PJM is subject to retail competition and will therefore benefit from reductions to LMPs. Applying the same rationale used to justify Midwest ISO's approach, National Grid argues that the correct allocation would be 30 percent production cost to 70 percent gross load payment for PJM.

59. Rockland argues that the 70/30 metric, which ignores the value of Auction Revenue Rights (ARRs), distorts the cost-benefit analysis because the benefits from production cost savings—essentially savings in fuel used to generate electricity—may accrue to generators who do not pay for transmission enhancements. It acknowledges that production cost savings could be used as an initial screen to determine a project's merit from a total resource perspective, but Rockland argues that the ultimate test should compare the savings to load, including the value of ARRs, with the cost borne by load.

60. Parties also raise various concerns about how load payments are calculated. For example, Dayton, PSEG and Rockland argue that voltage should have no bearing on how PJM calculates load payments. The appropriate method, they argue, which PJM uses for transmission projects rated at 500 kV and above, is to estimate benefits on a system-wide basis for all economic transmission projects. They argue that by acknowledging the benefits accruing to the "winners" and ignoring the increased payments made by the "losers" for lower voltage projects, PJM's proposed test may approve economic transmission that actually increases overall energy and capacity payments when viewed on a PJM-wide basis. They explain that certain PJM studies show that some transmission enhancements between uncongested western PJM and the congested eastern portions of PJM would increase LMPs in the uncongested areas in the west.

61. Parties also raise concerns about how the metrics fail to account for important consequences of changes in LMPs and RPM auction clearing prices beyond the effects on load payments. Dayton, for example, notes that PJM's proposal undercuts price signals provided by LMP and RPM. In its view, the eastern part of PJM has underinvested in generation and the production cost benefit metric biases PJM's planning decision toward construction in areas where fuel costs are cheapest (i.e. the west). Instead of incenting generation in eastern load pockets (like LMP and RPM mechanisms do), Dayton is afraid that the RTEP with the proposed metric will raise LMPs in uncongested areas in the west. Rockland also expresses a similar concern that the proposed test will give generators an

incentive to locate in a lower cost area and wait for PJM to build economic transmission fully funded by load.

62. Exelon, PSEG, Rockland and Dayton, also argue that the load payment metric should reflect net, rather than gross, payments by customers, i.e. deduct the value of hedging rights such as Auction Revenue Rights (ARRs) and Capacity Deliverability Rights (CDRs). Rockland argues that the offsetting value of ARRs for a transmission project can be fully 2/3 of the gross load payment savings. Old Dominion, however, disagrees, and suggests that consideration of "unhedgeable" congestion tends to mask "the economic reality that hedging itself has costs and does not result in a true measure of the robustness of the transmission system."

2. <u>Commission Determination</u>

63. We accept PJM's proposal to weigh production-cost savings and load payments 70/30 in the benefits formula as a reasonable basis for deciding whether specific economic transmission projects should be included in the RTEP. We find that, consistent with our decision in *Midwest Independent Transmission System Operator, Inc.*,[16] the 70/30 percentage provides a just and reasonable balance of resource savings and savings to load. The resource or production cost savings measure the economic benefit of the project, while the load payments measure the extent to which the project will reduce prices to load.

64. We do not agree with Dayton that the production cost metric should be given no weight, or with PSEG and National Grid that it should receive less weight than that proposed by PJM. Production cost savings measures the total economic benefit of a transmission expansion to the market. The total economic benefit of an expansion is equal to the total producer benefit[17] plus the total consumer benefit[18] resulting from the construction of the contemplated transmission project. As a result, if the production cost savings exceed the cost of the transmission project, the project is one that produces

[16] *Midwest Independent Transmission System Operator, Inc.*, 118 FERC ¶ 61,209 (2007).

[17] The total producer benefit is the increase in net generator revenue that would result from the building of the transmission project. To determine the total producer benefit, one calculates the difference in producer benefit (total gross generator revenue minus total generator production costs) with and without the transmission project.

[18] The total consumer benefit is the decrease in net load payment that would occur as a result of the transmission project. To determine total consumer benefit, one calculates the consumer benefit (total gross load payments minus total FTR/CTR credits) with and without the transmission project.

overall benefits to the market. Because the inclusion of the production cost metric identifies projects that produce cost savings, we find PJM's inclusion of the production cost metric just and reasonable.

65. We will also reject protestors' suggestion to reverse the weights due to the fact that PJM has more retail competition than the Midwest ISO. As we explained above, production cost savings measures the combined benefits to both producers and consumers. We conclude that it is reasonable to give a larger weight to the metric that measures the net benefit to the market as a whole. From an economic perspective, if the savings in production over the time horizon due to access to cheaper power exceeded the cost of building the transmission line, then it would provide net benefits and should be built. Since this result is based on the benefits and costs of the project, it does not depend on the structure of the market or the amount of retail competition.

66. We disagree with the protestors who argue that voltage should have no bearing on how PJM calculates load payments. In PJM, different cost allocation rules apply for new transmission projects depending on voltage. The costs of new projects rated 500 kV and above are assigned to all loads in PJM, while the costs of new projects rated less than 500 kV are assigned only to the loads that benefit from the projects. Since the cost assignment differs depending on voltage, it is reasonable to measure load payment benefits differently depending on voltage. Specifically, since the costs of projects rated 500 kV and above will be assigned to all loads, it is reasonable to consider the changes in load payments aggregated over all PJM loads, as PJM proposes.

67. Some protesters object to PJM's proposal for measuring the load payment changes associated with projects rated less than their 500 kV. PJM proposes summing the energy benefit metric for transmission facilities less 500 kV for only those zones that experience reduced energy payments – which are the zones that would be assigned the costs of these facilities – and not to include the expected energy payment increases, if any, in other zones. Thus, for projects that have costs allocated using a flow-based methodology, PJM proposes to consider only the change in load payment for only those PJM zones that show a decrease in load payment. We find this approach reasonable because it would match the project selection process to the existing cost allocation method. That is, it would evaluate the load payment benefits of those loads that will be assigned the costs of the new facilities.

68. However, we agree with Exelon, PSEG, Rockland, and Dayton that an accurate measure of actual load benefits must consider the effect of transmission projects on the value of hedging rights such as ARRs and CDRs. Such financial transmission rights allow loads in an import-constrained area to effectively purchase a portion of their energy at the LMP at the source point of the rights outside the load pocket. PJM ignores the existing ARRs and CDRs in calculating load benefit. It calculates load benefit by taking the price reduction in the load pocket resulting from a project and multiplying that

reduction by the total MW of load in the load pocket. Suppose that an existing transmission line is 10 MW, and PJM is contemplating a transmission project that would add 5 MW to the line, and the project would reduce LMP price by $10 in the load pocket. If the load pocket has 15 MW of load, PJM would calculate load benefits of $150 (15 MW x $10).

69. But this calculation ignores the ARRs and CDRs on the existing 10 MW transmission line. Prior to the project, load already could purchase 10 MW of power from the source point outside the load pocket at a price lower than the price inside the load pocket. Thus, the load will not receive the $10 cost savings on all 15 MW of load, but only for the 5 MW that exceed the existing transmission line. In fact, it may well be that the 5 MW transmission expansion may increase the generation prices outside the load pocket since greater demand outside the load pocket may result in higher generation prices outside the load pocket. This will result in higher costs to load inside the load pocket to the extent that the congestion revenues received from their FTRs is reduced, thereby reducing the benefit that the load paying for the expansion receives. As a result, PJM's formula for calculating load benefit overstates the benefit to load from a transmission project.

70. PJM argues that it already considers FTRs in its production cost analysis. But it does not explain why FTRs should therefore be ignored in the load benefit analysis, particularly since the point of this analysis is to correctly measure the benefits to load. Since FTRs affect the determination of load benefits as discussed above, we therefore will accept PJM's filing to include load payments in its metric on condition that it calculates load payments net of the change in the value of transmission rights. PJM should submit a compliance filing within 60 days of this order incorporating this change in its tariff.

71. The formulaic approach submitted in PJM's compliance filing is also a consensus proposal reached by the PJM stakeholders through extensive negotiation and compromise. Notably, only a handful of stakeholders object to the filing (Members Committee members voted 3.88 for the proposal and 1.22 against, in sector voting). While there is no one perfect formula by which to evaluate the benefits of economic-based transmission enhancements and expansions, the consensus approach developed by PJM and stakeholders is a just and reasonable means by which to measure whether an economic-based enhancement or expansion should be included in the RTEP.

C. Cost-Benefit Ratio and Planning Horizon

72. As stated above, PJM proposes for its benefit/cost ratio a constant threshold of 1.25 to one, regardless of the in-service date of the enhancement or expansion. PJM's ratio would compare the net present value of annual benefits to that of annual costs of a

proposed upgrade or project over a 15 year period, starting from the project's in-service date.

1. **Protests**

73. Regarding PJM's compliance filing, several parties argue that the proposed 15 year planning horizon is too long and that PJM's benefit/cost ratio is flawed.

74. Dayton and Rockland suggest shortening the period to 7 years while Exelon argues for a 6-year planning horizon. These parties contend that, under PJM's proposal, the 15 year analysis period for economic transmission projects would not begin on the day the economic analysis is performed, but rather on the day the proposed economic project is estimated to go into service. Given that typical lead times range from three to 10 years to plan, site, construct and commission a new transmission facility, the proposed test could forecast costs and benefits up to 25 years in the future. These parties point to fuel price fluctuations and other factors that would make such long-term forecasts extremely unreliable.

75. PSEG suggests that PJM's proposed planning horizon does not align with the current three-year time frame for PJM's Reliability Pricing Model (RPM) capacity auction and does not require PJM to re-model the system based on the RPM auction results. In order to address this problem, PSEG suggests shortening the planning horizon to five to ten years from a project's in-service date.

76. Rockland suggests that if the 15 year analysis period is not shortened, the Commission should modify the proposed test's fixed benefit-to-cost threshold of 1.25 to account for the greater riskiness of projects with in-service dates that are far in the future. Rockland adds that PJM has approved a total of $9.3 billion of transmission enhancements in the last eight years. Even though these projects, argues Rockland, have been justified based on reliability needs, many also have economic impacts on the PJM energy and capacity markets. Thus, PJM's justification for using a more liberal standard than the Midwest ISO, namely the critical need for additional transmission, is already being accomplished through reliability upgrades.

77. As another alternative, PSEG and Rockland argue for a sliding-scale approach that would be similar to the type approved for the Midwest ISO. Under Midwest ISO's approach, projects with an in-service date one year from the date when they are approved in the planning process would have to meet a benefit/cost ratio of 1.2 to one, while projects with an in-service date of ten years or later would have to satisfy a benefit/cost ratio of three to one. PSEG notes that when the Commission approved Midwest ISO's sliding-scale approach, we recognized that a benefits calculation involved many assumptions from future fuel prices to load growth to generator entry and retirement, and that a sliding scale could help ensure that actual benefits would materialize that were commensurate with the costs of economic upgrades.

78. PJM in its answer argues that while there always is uncertainty when forecasting the costs and benefits of a potential upgrade, using the first 15 years of the life of the facility as the evaluation period reasonably balances the inevitable uncertainty with the obvious need to consider the benefits that will occur in the future. PJM states that the generally accepted depreciable life span of a transmission facility is 30 years. Therefore, using only the first 15 years likely produces conservative estimates of the benefits of a facility ameliorating the uncertainty inherent in any future projection, while still effectively reflecting the future benefits of the upgrade. Evaluation of benefits over short time frames could ignore significant benefits of an upgrade that would occur beyond the limited evaluation period and would tend to discourage the development of long-lived asset solutions.

2. **Commission Determination**

79. The Commission finds that 15 years is a reasonable period of time for PJM's planning horizon in order to calculate the costs and benefits of economic projects that will remain in its system for decades. It matches PJM's overall planning horizon and sends signals for new construction that has long-term benefits. In circumstances where purely market-design changes would not elicit sufficient construction, the Commission supports proposals that "create a long-term commitment . . . where the problem is projected to be a long-term one."[19] We recognize concerns that predictions about the distant future can be uncertain, but we agree with PJM that any predictions about system conditions are inherently uncertain. But rather than further shrink the planning horizon to some arbitrary period that is less than 15 years, the better practice is to mitigate the uncertainty of system-condition predictions with a clear, conservative formula and robust stakeholder process. We find that PJM has done this. Its bright-line formula uses a benefits/cost ratio of 1.25 to one, ensuring that even at the end of the planning horizon, projects benefits are larger than costs. Indeed, benefits are discounted by PJM's present value formula as PJM looks at projects with benefits further out in its planning horizon, such projects will have a more difficult time offsetting costs. We note that 15 years is substantially less than the useful life of many transmission projects. Further, PJM will perform sensitivity analyses around key inputs. For these reasons, we find PJM's planning horizon to be just and reasonable.

80. Similarly, we will deny the request of PSEG and Rockland to require a sliding scale, whereby the required minimum benefit-cost ratio would increase for projects with more distant in-service dates. We note that while we have accepted a sliding scale for the Midwest ISO, PSEG and Rockland have not demonstrated that the fixed ratio proposed by PJM is unreasonable. Use of a sliding scale involves tradeoffs. It would avoid

[19] *PJM Interconnection, L.L.C.*, 107 FERC ¶ 61,112, at P 21 (2004) (footnotes omitted), *order on reh'g*, 110 FERC ¶ 61,053 (2005).

accepting projects whose more distant expected benefits (which are inherently more difficult to estimate) would fail to materialize. On the other hand, it would also exclude some projects whose distant benefits would actually materialize.

D. Voting

1. Protests

81. PSEG has renewed its objection that the proposal failed to include a voting mechanism for economic projects. In addition, Dayton and Rockland have filed protests, objecting that PJM's proposed test does not provide a way for customers to vote.

82. Rockland argues that, since economic transmission projects are not necessary for reliability, it is only reasonable to permit the entities paying for the economic upgrade to vote on whether the project should proceed to construction (it notes that PJM allows for voting on items that have a far greater potential impact on reliability). It states that voting is especially important because entities paying for an economic upgrade may not actually receive some of the proposed benefits, even if PJM's forecasts of the benefits are accurate. Rockland argues that the Commission has previously noted the benefits of customer participation in the transmission planning process.[20] Accordingly, it proposes a plan where a super-majority of beneficiaries (at least 80 percent, it suggests) would have to support a project prior to its inclusion in the PJM RTEP. Voting rights would be allocated pro-rata in accordance to each customer's obligation to pay for a project. It states that the 80-percent super-majority threshold ensures that only projects with wide-spread support will be built, but also prevents a small minority from blocking a project. According to Rockland, for projects approved by the super-majority, all customers with a cost obligation would pay, regardless of how they voted on a project, thereby eliminating the issue of free riders.

83. Similarly, PSEG supports inclusion of a "30-percent-to-30-percent" voting rule (30/30 rule), that has been used in Argentina and which is described and supported in the testimony of William W. Hogan.[21] Under the 30/30 rule, votes are cast and weighted based on the customer's actual cost-allocation responsibility. Ultimately, at least 30 percent of the beneficiaries must vote in favor of the proposed expansion and no more than 30 percent can vote in opposition for the expansion to get built. PSEG states that NYISO is considering a super-majority voting procedure.

84. Dayton also suggests that PJM should allow those who bear the costs to become partial owners of the transmission projects.

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[20] *Citing* Order 890 at P 561.

[21] PSEG October 30, 2007 Protest at 14.

85. In addition, LIPA suggests that PJM return the following (underlined) language to section 1.5.7(c)(ii) of Schedule 6: "The PJM Board <u>upon consideration of the advice of the Transmission Expansion Advisory Committee</u> thereafter shall consider and vote to approve any accelerations that are eligible for inclusion in the Regional Transmission Expansion Plan in accordance with subsection (d) of this section 1.5.7."

2. **<u>Commission Determination</u>**

86. We cannot find that the proposed voting mechanisms are necessary to a just and reasonable methodology for identifying economically viable transmission projects. As discussed above, PJM's metrics provide a just and reasonable method of identifying transmission projects with benefits that exceed the costs of the project.

87. LIPA suggests re-inserting the phrase "upon consideration of the advice of the Transmission Expansion Advisory Committee" in order to permit PJM to decline to include an economic-based project in the RTEP even if it has passed the bright line test. PJM maintains that it removed this phrase because it goes against the Commission's June 11 Order. We disagree that without this language PJM's compliance filing is unjust and unreasonable. PJM now will be implementing a formula, as required by the Commission, to determine whether to include economic-based upgrades in the RTEP. LIPA's suggestion to re-insert the phrase "upon consideration of the advice of the Transmission Expansion Advisory Committee" would permit PJM to decline to include an economic-based project in the RTEP even if it has passed the bright line test, based on the advice of the TEAC. This is contrary to the directive in our June 11 Order that there be a bright line formula and will be rejected.

E. **<u>Discount Rate and Recovery Period</u>**

1. **<u>Protests</u>**

88. Exelon argues that PJM has not provided specificity concerning the discount rate to be used by PJM.

89. Rockland argues that PJM's proposed test does not indicate what the assumed recovery period is for economic transmission projects. This lack of an assumed recovery period is critical because it creates a potential disconnect between what customers will actually be obligated to pay and what the proposed test assumes they will pay.

2. **<u>Commission Determination</u>**

90. We agree with the protestors' concern that the lack of specificity with regard to the discount rate and the assumed recovery period may lead to potential disputes, and does not comply with our June 11 Order. We will therefore accept PJM's filing subject to the

condition that PJM include in its compliance filing a more specific description of the method of determining the discount rate and recovery period.

F. Project Acceleration Costs

1. Protests

91. Strategic Transmission Company is concerned that one aspect of the filing is incomplete, namely a formulaic approach to the cost of accelerating, for economic reasons, a reliability-based RTEP project. According to Strategic, the proposed tariff language only speaks in terms of the "Total Enhancement Cost" which is defined as the "estimated annual revenue requirement for the economic-based enhancement or expansion." Strategic states that the costs of acceleration should only be limited to an objective measure of the time value of money such as the discount rate. The time value of money approach to costing acceleration of a reliability-based RTEP project would reflect the concept that project elements scheduled for year X could be done earlier -- such as year X - 1 or year X - 2. Strategic argues that in Docket No. EL07-63, PJM took the position that, in the context of a proposed merchant-transmission project, an individual transmission owner could go beyond an objective time value of money approach.

92. PJM in its Answer argues that there are many factors such as overtime scheduling, siting issues, and others that bear on the ability of a transmission owner to accelerate a project and the cost of accelerating that project. PJM argues that the costs to accelerate a reliability-based transmission upgrade involve far more than just "the time value of money" associated with the acceleration. To narrow such costs in the formula for determining the viability of an economic-based project, as Strategic suggests, could underestimate the costs of such projects and thus distort the determination of the costs and benefits of such a project when evaluating it for inclusion in the RTEP.

2. Commission Determination

93. The language to which Strategic points defines the "Total Enhancement Cost" as the "estimated annual revenue requirement for the economic-based enhancement or expansion." We find that this definition applies equally both to pure economic projects and to accelerations of reliability projects. It reflects the transmission owner's estimated revenue requirement that is, in turn, based on its determination of the costs of the project, and we see no need in this proceeding to define this term more specifically for accelerated projects than for other projects.

94. Strategic appears to be arguing that the costs for accelerated projects should be limited to the time value of money based on an issue raised in Docket No. EL07-63

regarding the acceleration of a merchant-transmission project.[22] The tariff provision at issue in the Docket No. EL07-63 proceeding, however, is not at issue in this proceeding. PJM should review all of its tariff provisions relating to cost estimates for accelerated projects to make sure that they reflect a consistent approach. PJM should make a compliance filing within 60 days of this order to clarify these provisions.

G. <u>Energy Policy Act</u>

95. Both the New Jersey Commission and PSEG argue that Energy Policy Act of 2005 ("EPAct 2005") does not support the economic planning that PJM proposes. The New Jersey Commission argues that the November 21 Order cites FPA sections 824s(b)(1), 824q(b)(4), and 824p(a)(2) as encouraging this type of economic planning. It states that the cited sections do not address the type of economic planning proposed by PJM, however, nor do they suggest that RTO should engage in this type of economic planning. Similarly, PSEG argues that PJM's filing is not consistent with the intent of Congress, because EPAct 2005 did not direct or authorize the Commission to take steps to require or encourage rate-based regulated transmission projects to address economic issues.

96. The economic planning process was required by the Commission.[23] We find nothing in the EPAct 2005 that forbids the kind of planning for economic projects contemplated in PJM's proposal.

97. Moreover, we continue to find that the Act supports the type of economic planning proposed by PJM. PJM's proposed goal is to promote economically efficient transmission by promoting capital investment in the enlargement, improvement, maintenance and operation of all facilities for the transmission of electric energy—a goal expressed in EPAct 2005.[24] The EPAct 2005 directs that the Commission adopt policies that will ensure that transmission is built to serve native load. Specifically, new section 217 of the FPA, added by the EPAct 2005, requires the Commission to exercise its authority "in a manner that facilitates the planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities to satisfy the[ir] service obligations." Creating an economic planning process that enables economic upgrades and market solutions to relieve congestion for native load is clearly consistent with the

[22] The issue raised in Docket No. EL07-63 was not decided because the proceeding was dismissed as moot. *Strategic Transmission, LLC v. PJM Interconnection, LLC,* 122 FERC ¶ 61,108 (2008).

[23] *PJM Interconnection, LLC,* 101 FERC ¶ 61,345 (2002).

[24] *See* 16 U.S.C. § 824s(b) (Supp. v. 2005).

EPAct 2005. Accordingly, we find that the EPAct 2005 does not prevent PJM from using economic planning, and we deny the rehearing requests on this point.

H. Sensitivity Analysis

98. In its latest compliance filing, PJM removed from section 1.5.7(c)(vii) the language requiring it to conduct sensitivity analyses. The June 11 Order did not require PJM to eliminate sensitivity analyses, and PJM has not provided sufficient justification for removing this provision. It would appear critical for PJM to test fuel prices, inflation rate and other assumptions used in the model. We will therefore accept the filing subject to PJM making a compliance filing either to reinstate the provision or to explain why sensitivity analyses are unnecessary.

The Commission orders:

(A) The requests for rehearing are hereby granted in part and denied in part, as discussed in the body of this order.

(B) PJM's compliance is hereby accepted in part and rejected in part, as discussed in the body of this order.

(C) PJM is hereby directed to submit a further compliance filing, within 60 days of the date of this order, as discussed in the body of this order.

By the Commission.

(S E A L)

Kimberly D. Bose,
Secretary.