ATTORNEYS AT LAW
WRIGHT & TALISMAN, P.C.
Washington, D.C.
www.wrightlaw.com

1 of 2

August 31, 2005

ORIGINAL

Honorable Magalie Roman Salas
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E. Room 1A
Washington, D.C. 20426

Re: **PJM Interconnection, L.L.C., Docket Nos. ER05-1410-000 and EL05-148-000**

Dear Ms. Salas:

PJM Interconnection, L.L.C. ("PJM") submits for filing under sections 205 and 206 of the Federal Power Act ("FPA"), 16 U.S.C. §§ 824d and 824e, its new Reliability Pricing Model ("RPM") modifying the existing capacity rules in PJM region to address current serious inadequacies. To accomplish these changes, PJM is revising its tariff,[1] its Operating Agreement,[2] and its various reliability assurance agreements,[3] consolidating

---

1 The PJM Open Access Transmission Tariff ("PJM Tariff").

2 The Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. ("Operating Agreement").

3 The Reliability Assurance Agreement among Load-Serving Entities in the Mid-Atlantic Area Council ("MAAC") Control Zone ("East RAA"), the Reliability Assurance Agreement among Load-Serving Entities in the PJM West Region ("West RAA"), and the Reliability Assurance Agreement among Load-Serving Entities in the PJM South Region ("South RAA").

PJM Interconnection, L.L.C.
Docket Nos. ER05-1410-000
and EL05-148-000

Reliability Pricing Model Filing

August 31, 2005

Volume 1 ORIGINAL

such agreements into a single Reliability Assurance Agreement among Load-Serving Entities in the PJM Region ("PJM RAA").

PJM proposes to replace its current capacity construct with RPM on June 1, 2006, which is the first day of PJM's next annual planning period. To that end, PJM requests that the Commission issue its final order on this filing no later than January 31, 2006.[4] Action by this date will provide certainty to market participants and ensure that PJM has sufficient time before the start of the next planning period to hold the RPM auctions used to determine the cost of capacity for that period. If the Commission does not act until after that date, then PJM likely will not be able to implement RPM in the annual period that runs from June 1, 2006 to May 31, 2007. Consistent with this approach, the enclosed tariff revisions related to conducting the auctions have an effective date of February 1, 2006, while the remainder of the tariff changes have an effective date of June 1, 2006.[5]

To the extent the Commission deems appropriate to meet this schedule, the Commission could issue an initial order approving the key features of the proposed RPM model, as specified below, and establish technical conference proceedings to establish the final just and reasonable parameters of the variable resource requirement ("VRR") curve used to clear the RPM auctions. This would be consistent with the Commission's orders on other recent filings to modify regional energy or capacity markets, in particular the recent capacity demand curve filing by the New York Independent System Operator ("NYISO"),[6] and provide stability to the financial community as it considers whether to invest in needed infrastructure in the PJM region.

In any such initial order, PJM requests that the Commission find that:

---

4 To the extent the Commission requires additional time to process the section 206 request in this filing, PJM consents to an effective date for the tariff and RAA sheets submitted under section 205 that coincides with the effective date the Commission establishes under section 206 for the operating agreement changes.

5 As both of these proposed effective dates are more than 120 days after the date of this filing, PJM requests waiver of section 35.3 of the Commission's rules, 18 C.F.R. § 35.3. Waiver is appropriate, as PJM is filing well in advance of the proposed effective dates to allow the Commission time to process the filing before it takes effect.

6 N.Y. Indep. Sys. Operator, Inc., 110 FERC ¶ 61,201, at PP 19-22 (2005).

1) PJM's current capacity pricing model and market rules fail to assure that reliability will be maintained at the lowest reasonable cost, and as such, are unjust and unreasonable; and

2) RPM's primary features, i.e.,

- valuing capacity resources by location;
- use of a downward-sloping variable resource requirement curve;
- four-year-forward commitment of capacity resources;
- recognizing the added value of capacity resources that preserve operational aspects of reliability;
- allowing planned generation, planned and existing demand resources, and planned transmission upgrades to compete on an equal basis with existing generation resources to meet capacity requirements; and
- explicit market power mitigation rules that directly address market-structure concerns of capacity markets

are just and reasonable. As shown in this filing, each of these elements of RPM conforms closely to Commission precedent, and warrants application in the PJM region to help ensure continued long-term reliability at reasonable cost.

This transmittal letter is organized as follows: following the executive summary in section I, section II describes recent changes to RPM and other initiatives resulting from PJM's dialogue to date with state commissions and other stakeholders. Section III demonstrates that the Commission already has approved for other Independent System Operators ("ISOs") or Regional Transmission Organizations ("RTOs") most of the critical elements of RPM. Section IV describes PJM's existing capacity mechanism, why it is not working, and why it should be found unjust and unreasonable. Section V lays out the RPM proposal and why it remedies the deficiencies of the current mechanism. Section VI describes certain related and conforming tariff changes needed to put RPM in place.

PJM's filing includes this transmittal letter, revised sheets of the PJM Tariff, PJM RAA, and PJM Operating Agreement (in both revised and redlined form) and the following supporting affidavits:

1 Affidavit of Andrew L. Ott, PJM Vice President of Market Services, in which he provides an overview of RPM, provides support for its four-year forward approach and variable resource requirement curve, presents an estimate of energy cost savings from RPM, explains RPM's integration of load management solutions, explains and supports RPM's seasonal capacity pricing provisions, operational reliability provisions, and reliability backstop provisions, and provides an estimate of PJM's administrative costs to implement RPM;

2. Affidavit of Steven R. Herling, PJM Vice President of Planning, in which he presents the history of measures to assure capacity adequacy in PJM, describes the PJM regional transmission expansion plan ("RTEP") process, describes reliability criteria violations recently experienced in PJM and PJM's response to those potential reliability issues, explains and supports RPM's locational capacity provisions, describes how RPM will more closely integrate the capacity market with the transmission planning process, and explains how transmission upgrades can compete in RPM to resolve potential reliability issues;

3. Affidavit of Joseph E. Bowring, Market Monitor for the PJM Region, in which he explains and supports the methodology used in RPM to calculate the net energy and ancillary services revenue offset to the cost of new entry; explains and supports the use of a nominal levelized financial model to calculate the cost of new entry; reviews the level of cost recovery realized by generators since the PJM energy market started operations in 1999; and explains and supports the market power mitigation rules filed as part of RPM;

4. Affidavit of Professor Benjamin F. Hobbs of the Johns Hopkins University, in which he describes the results of his dynamic economic analysis of various VRR curves under consideration for use in RPM; and

5 Affidavit of Ray L. Pasteris, President of Strategic Energy Services, Inc., in which he supports the estimated cost of new entry used in RPM.

I. EXECUTIVE SUMMARY

Although the Commission repeatedly has affirmed that capacity adequacy commitments are appropriate for the PJM markets, PJM's current capacity adequacy rules have proven to be unjust and unreasonable. Based on PJM's extensive experience with the current capacity construct, that construct has the following serious shortcomings:

- it does not look far enough into the future to secure capacity in time to meet reliability needs;
- it lacks an important locational element;
- it is not providing sufficient financial incentives for supply additions; and
- without revision, it will not ensure the future reliability of the region.

The changes proposed through RPM, as detailed in this filing, are just and reasonable, as they address the above shortcomings in a comprehensive manner, with a sound market mechanism, and are fully consistent with Commission precedent.

A. Shortcomings of the Current Capacity Construct

1. No recognition of locational value

Recent events underscore that PJM's current capacity market rules no longer provide adequate assurances of continued regional reliability. PJM's current tariff rules, which do not differentiate capacity prices by location, do not reflect the fundamental reality that the system's ability to deliver energy can vary by location. PJM has seen few generation additions, but high rates of generation retirements, in some of the same areas in the PJM region where load is growing fastest. As a result of these trends, in particular a spate of actual and announced generation retirements, part of the PJM system—the state of New Jersey—faces violations of reliability criteria in each of the next four years. Other parts of the eastern PJM region (including the Baltimore–Washington area and Delmarva Peninsula) are trending toward similar violations, due to high load growth and comparatively low generation additions. Plant retirements in those areas, which the Commission allows on as little as 90-days notice, could throw these areas into reliability violations as well.

While PJM is responding to the current violations and assuring reliability, the available tools—installing transmission upgrades and delaying generation retirements—are not optimal; and the current system has no mechanism (or price signals) to bring forth the generation, transmission or demand resource solutions that can remedy reliability violations in the shortest time and at the lowest cost. Reflecting this focus on transmission solutions, PJM's most recent RTEP included an unprecedented level of "baseline" transmission upgrades needed to assure reliability—over $600 million worth. Moreover, in the areas of the system with potential deliverability issues, PJM is exhausting the lower-cost transmission upgrade options and faces considerable costs and lead times if the region must rely only on transmission upgrades to deal with future reliability issues or keep pace with continued vigorous load growth. While long-term transmission planning is a vital element in a holistic approach to these issues, sustainable price signals for generation and demand resources are also needed to ensure that all of these resources work together through competitive processes to meet future load growth and deliverability needs.

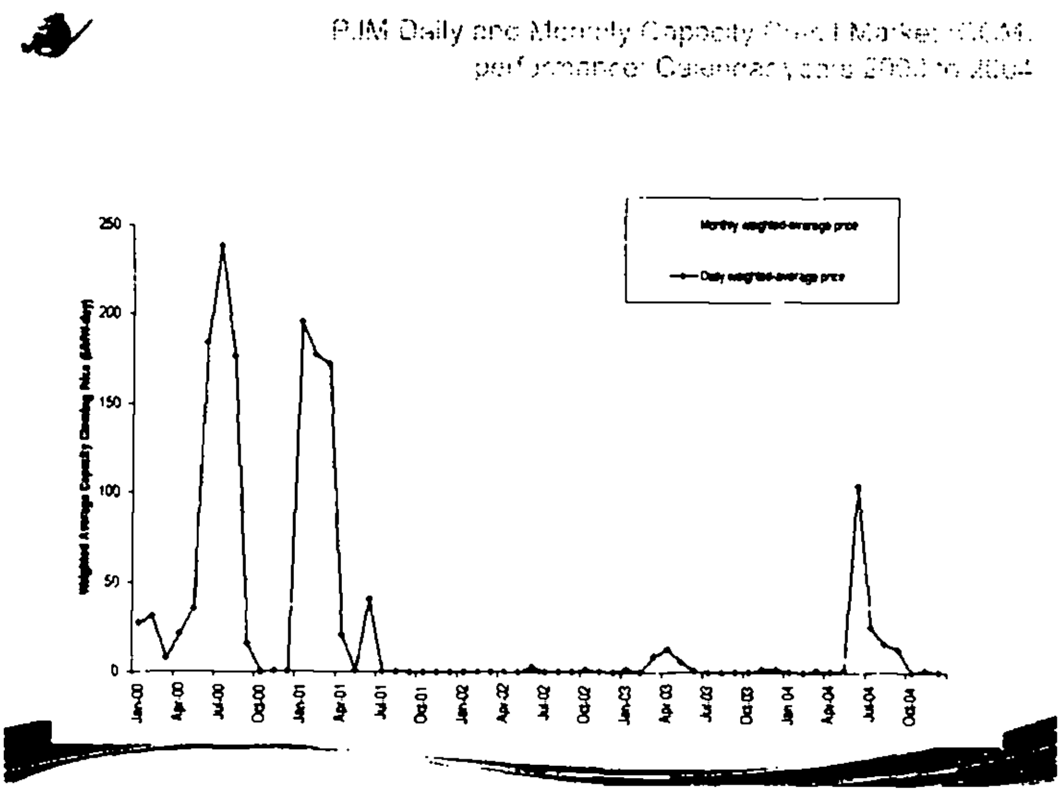
PJM also has been forced to invoke its recently approved generation retirement rules to retain in service units needed for reliability that had announced their retirement. As the Commission often has held, this is a temporary and sub-optimal solution. Such compensation, like the reliability must run ("RMR") contracts allowed elsewhere, is outside the market, and permits no competition from, and sends no price signals to, other prospective solutions (such as new generation or demand resources) that might be more cost-effective. As the Commission has recognized, the disadvantages of this out-of-market solution become especially acute if such compensation arrangements proliferate, as can happen where there are a number of older units with borderline economics that nonetheless are needed for reliability. Moreover, because the units announcing their retirement tend to be at the end of their useful lives, there are prudent limits to how long the system should depend on those units for local reliability. Under current circumstances, however, PJM has little option but to retain such units until necessary transmission upgrades are placed in service.

2. Volatile prices below replacement cost of marginal unit

The recent spike in announced retirements of older, marginally economic units also provides a warning that generator revenues in PJM may not be adequate to sustain the investments needed to maintain reliability in all parts of the PJM region. Under PJM's current capacity mechanism, daily and monthly capacity prices have been very volatile. As can be seen in Figure 1, daily prices in the PJM capacity credit market were at or near zero for most of the five years from 2000 through 2004, with occasional spikes (some lasting a few months) well over $100 per MW-day. Prices in the monthly market have shown similar, but somewhat less extreme, swings.

Figure 1

PJM Daily and Monthly Capacity Credit Market Clearing Prices
Calendar Years 2000-2004



Moreover, net revenue to generators from all sources since the PJM market started in 1999 has been insufficient to cover the cost of investment in the most efficient marginal capacity unit, i.e., a gas turbine peaking unit. As PJM's Market Monitor, Joseph E. Bowring, observes in his affidavit, "net revenue has been below the level required to cover the full costs of new generation investment for several years, and below that level on average for new peaking units for the entire period PJM has operated an energy market."[7]

7 Bowring Affidavit at 15.

PJM's current capacity construct contributes to this volatility and revenue inadequacy. That construct assesses a capacity deficiency charge based on the costs of a new peaker if the load serving entity ("LSE") commits less capacity than is required by the region-wide installed reserve margin ("IRM"). The IRM, currently set at 15%, is the margin of additional reserves set each year by the PJM Board of Managers, based on PJM staff technical analysis and the recommendation of the stakeholder Reliability Committee. In a single-valued deficiency charge structure such as PJM's, 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.

It is not surprising then, that the current construct, with prices very high just below the IRM, and very low just above the IRM, exhibits volatile pricing behavior, depending on whether there is too little capacity or too much relative to the target IRM. This is just the sort of behavior predicted for a single-value deficiency charge system by PJM's witness Professor Benjamin F. Hobbs in his affidavit. As part of his assessment of differing clearing methods for use in RPM, he evaluated the performance (in terms both of reliability and cost) of a "vertical" demand curve, similar to PJM's current capacity pricing structure. Applying a dynamic economic model, and conducting numerous sensitivity analyses, he found that in every scenario considered, the vertical demand curve was more volatile, more risky, yielded lower reliability, and resulted in higher consumer costs, than downward-sloping resource curves of the type recommended for RPM.

3. No long-term forward commitment or forward price signals

PJM's current rules require capacity resources to be committed for as short as one day, with limited incentives to commit resources for several months. Under the current rules, capacity resources can opt out of ("de-list") their capacity resource status with as little as 36 hours notice. Moreover, under the current rules, PJM administers capacity credit markets only for the succeeding twelve months. These short-term capacity markets were designed to accommodate short-term competitive load-switching under retail choice, but have not demonstrated the capability to sustain long-term generation investment. Nor do they provide any opportunity for new planned generation or demand resources to compete with existing resources to meet capacity requirements. Simply put, the short-term nature of the current PJM capacity adequacy construct is fundamentally inconsistent with the need to preserve system reliability in the longer term.

In addition to these major shortcomings, the current PJM capacity construct also:

- provides no meaningful opportunity for demand resources to compete to satisfy reliability requirements;
- has no mechanism for direct competition between merchant transmission projects and local generation to resolve load deliverability problems;
- places no added value on generation resources providing important load-following and thirty-minute-start capabilities, even though the amount of those additional capabilities offered to the system is declining; and
- contains no explicit provisions to address market power concerns that can arise with capacity markets.

B. RPM Comprehensively Addresses the Flaws in the Current PJM Capacity Adequacy Construct

RPM addresses the deficiencies in the current capacity construct in a comprehensive and integrated manner. It brings together critical features that provide:

- appropriate consideration of locational needs;
- four-year forward certainty for loads and suppliers;
- reduced risk and volatility, greater reliability, and lower consumer costs through use of a downward-sloped VRR curve;
- comprehensive market-based pricing of planned and existing generation supply, transmission alternatives, and demand-side resources;
- appropriate consideration of operational requirements; and
- explicit market power mitigation rules.

Moreover, as explained in section III below, the Commission already has approved (or accepted in principle) for other markets most of the critical elements of RPM.

1. Overview of RPM

Under RPM, PJM will administer a series of auctions as a vehicle for loads to secure capacity commitments and to establish corresponding reliability charges for each year. The first auction, conducted four years ahead of the year at issue (known as the "Delivery Year"), will commit any capacity resources needed by loads after taking account of all self-supplied and bilaterally contracted resources.[8] Subsequent incremental auctions will provide a mechanism for market participants to commit additional resources for the Delivery Year if needed to replace previously committed resources that have become unavailable, or if needed as a result of a significant increase in the forecast load for the year at issue. This structure supports both long-term commitments and near-term changes in those commitments, optimizing both reliability and flexibility. Because it is conducted four years in advance, the auction also provides a meaningful opportunity for planned new resources whether generation, demand, or transmission —to compete to satisfy reliability requirements.

The auctions will set the market-clearing prices paid during the Delivery Year to resources that cleared (i.e., offered to sell capacity at or below the clearing price) and the locational reliability charges that will be borne by LSEs during the Delivery Year on behalf of their loads. As stated above, LSEs can offset these charges with their owned or contracted resources, such that they are both receiving the resource payments and paying the load charges.

The RPM auctions can result in clearing prices that vary by area, reflecting the higher value of capacity located in constrained areas. For this purpose, RPM will use the areas identified in the planning process as those that have limited ability to import capacity. This locational aspect is crucial, providing pricing signals and incentives for generators, transmission owners, or demand resource suppliers to apply their solutions to areas that are trending toward deliverablity problems.

---

[8] To ensure all loads are covered, an LSE will offer its owned or contracted resources into the auctions, but with a "price-taker" bid. When it does so, its resources automatically will clear; it will receive RPM revenues during the Delivery Year as the seller of a capacity resource, and it will pay RPM reliability charges during the Delivery Year as an LSE.

Similarly, if either or both of the operational reliability constraints bind in the auction, resources supplying load-following or 30-minute-start capabilities (as applicable) will receive a higher price, based on the minimum price adder needed to attract the required level of those resources. This ensures that such resources will be appropriately compensated, and gives operators an incentive to maintain or install generation units that help PJM meet these crucial operational needs.

2. VRR Curve

The auction-clearing model will take into account all submitted supply offers and the VRR curve, which will replace the current single-value deficiency rate. Rather than valuing all capacity below the IRM at a single deficiency rate, and all capacity above that margin effectively at zero, the VRR curve recognizes the graduated, and declining, value of capacity at levels above and below the required margin.[9] When the VRR curve clears above the IRM, i.e., commits more capacity than the 15% margin, the overall cost of all capacity to the market (not simply the unit cost) is lower. As illustrated in Table 1, the clearing price from the VRR curve at 15% reserve margin results in a total capacity cost of $27 million/day; but if the auction clears capacity resources providing a 16% reserve margin, the total capacity cost drops to $19 million/day. This relationship stems from the design of the curve, and holds for each increase in the cleared reserve margin, as shown in Table 1:

[9] The proposed curve is shown on page 69. As discussed there, the auction generally sets the clearing price at the intersection of the VRR curve and the supply curve formed by the submitted sell offers.

Table 1

When the VRR Curve Clears Above the IRM, It Clears More Capacity at Less Cost

Region-wide Unforced Capacity Obligation 147321

Reserve Cleared by Auction	Capacity Cleared MW	Capacity Price from VRR $/MW-Day	Capacity Cost $ Million per Day	Reduction in Cost $ Mil/Day	Reduction in Cost $ Bil/yr
12%	143478	340	49	0	0
13%	144759	288	42	7	3
14%	146040	235	34	15	5
15%	147321	182	27	22	8
16%	148602	129	19	30	11
17%	149883	119	18	31	11
18%	151164	109	16	32	12
19%	152445	99	15	34	12
20%	153726	89	14	35	13

The table above shows only the capacity cost savings. Under RPM, the capacity cost savings shown above will be augmented by energy cost savings. In addition to the capacity savings, commitment of resources above the target IRM should lower the cost of energy to LSEs, as higher capacity reserve margins will enable greater competition. To illustrate this, PJM simulated locational marginal prices under varying reserve margin scenarios, and found substantial savings. For example, the energy costs borne by LSEs went down by $936 million if capacity is cleared at an 18% reserve level, compared to the cost of capacity cleared at a 15% reserve level.

Although a downward-sloping curve, like the current deficiency charge, is administratively determined based on the estimated costs of new entry, extensive analysis by Professor Hobbs shows that it will produce much better performance yielding greater assurance of reliability at lower cost than the current single deficiency rate approach. At PJM's request, Professor Hobbs tested numerous possibilities for the shape and placement of the VRR, examining dozens of sensitivities and permutations. Based on his extensive work, PJM selected for initial use in RPM the curve that offers the best combination of high reliability and low long-term cost. Because it places high value on finding a solution that works best for the region, PJM commissioned extensive testing (as discussed by Professor Hobbs) on the curve selected for this filing.

Nevertheless, PJM recognizes the critical importance of the precise slope and placement of the VRR curve, and thus anticipates, and welcomes, close scrutiny and further analysis and testing of the curve as the Commission considers this application. As suggested above, the Commission may wish to hold a technical conference to fully air the issues surrounding the elements of the VRR curve. While no test or analysis is a full substitute for actual experience (and thus PJM's proposal calls for a periodic re-examination of the VRR curve every three years), PJM acknowledges that a thorough and careful consideration of the initial curve is warranted here. For example, the Commission may want to consider in particular the states' assessments of the appropriate balance between certainty and cost in light of the states' obligations to their constituents.

As discussed in more detail in this filing, RPM also includes provisions designed to protect against potential market power, including market structure tests and avoidable-cost determinations similar to those used in other PJM markets.

II. PJM'S ACTIONS TO ADDRESS THE CONCERNS OF STATE COMMISSIONS AND OTHER STAKEHOLDERS

This filing follows years of effort by PJM and stakeholders to reform capacity rules, including scores of meetings, intensive review of the RPM proposal for over a year, two presentations by stakeholders directly to the PJM Board of Managers, and a Commission-sponsored technical conference earlier this year. While consensus on a successor to PJM's current capacity construct remains elusive, PJM has heard the concerns raised during this process by state regulatory commissions, end-users, load-serving entities, and other stakeholders, and has made a number of changes to the proposal, and instituted other initiatives, to address those concerns. These changes, some adopted after the technical conference, have been reviewed with state commissions and stakeholders.

A. *Transmission Planning Reforms*

PJM has taken to heart the message that reforms are needed in the current RTEP process. Recognizing that "the level and nature of transmission investment required for the region requires a longer time period" than the five-year planning horizon in the current RTEP rules, the PJM Board of Managers has directed PJM to work with stakeholders to develop protocols that embed a longer-term view in the planning process.[10] Moreover, while PJM has implemented a Commission-approved economic planning program, it is not clear that those recently adopted rules "are achieving the desired outcome of ensuring adequate transmission investment to support robust competitive markets."[11] The PJM Board therefore has directed PJM to review its current economic planning process and work with stakeholders to identify appropriate changes.

Accordingly, PJM is working with the states and stakeholders to shape enhancements to the RTEP rules, with a goal of filing such changes with the Commission in the near future. PJM will be working with its members and state commission to refine its planning process, and in particular to resolve:

(1) how far into the future the process should look;

(2) how to account for the possibility that older or less economic "at-risk" generation units may retire during the planning horizon; and

(3) the specific kinds of econometric modeling that should be incorporated into the process.

This RTEP initiative does not eliminate the need to reform capacity markets in PJM, not are RTEP reforms a condition precedent to capacity market reforms. As Mr. Herling explains in his affidavit, PJM designed RPM to give equal treatment to generation, transmission, and demand resource solutions for locational reliability needs, so all resources can compete in the RPM auctions. Where transmission solutions are more cost-effective than installing generation, those transmission solutions will be selected in the auction. While the current transmission 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.

---

[10] See Attachment 1 to Mr. Herling's Affidavit.

[11] Id.

Moreover, as Mr. Herling also explains, extending the transmission planning horizon makes it all the more important to provide for forward commitment of capacity. This will reduce uncertainty concerning elements of the long-term system plan, including the level of generation additions and the level, nature, and scope of load management programs.

Accordingly, while PJM will work diligently with stakeholders on enhancements to the RTEP rules, capacity market reform also must go forward.

B. *Accommodating Evolution of the Energy Market*

In meetings with state commission representatives, concerns have been expressed that PJM take steps to ensure that the capacity regime is self-correcting, and not inhibit evolution of the energy market to a greater role in assuring reliability. PJM agrees that capacity markets should diminish in importance to the extent energy markets in the future prove capable, standing alone, of offering adequate assurance of reliability. Accordingly, the RPM proposal PJM is filing today includes provisions that will automatically de-emphasize the capacity market as the energy market proves more effective at incenting adequate capacity resources. Specifically, PJM has designed the variable resource requirement curve to reflect changes in the level of revenues received by generators from the energy and ancillary services markets; this revenue offset will reduce capacity prices as generation owners receive more net revenue from other sources. As a result, the RPM design will automatically track any transition towards greater emphasis on energy market prices, whether in connection with changes to the offer price cap,[12] development of scarcity pricing, or evolution of load management techniques and compensation.

PJM considered, but does not recommend in this filing, developing a specific "trigger" mechanism that would result in an automatic modification or elimination of the capacity market. Some parties suggested, for example, that once demand response participation in the market reached a pre-determined level, RPM would be eliminated.

[12] Evolution of the contribution provided by load management, for example, may well enable changes to the current $1,000/Mwh energy market offer cap.

While PJM agrees that the rise of demand response to greater prominence in the wholesale and retail markets will have an important impact on the efficiency of the energy market, and may well allow a de-emphasis of the capacity market, PJM believes that it would be imprudent to attempt to predict, at this point in the development of the markets, the precise point at which demand response has become "sufficiently" established, and beyond that whether its establishment warrants the elimination or only a modification of any capacity construct. PJM believes that the structure of RPM itself, which will (as described above) tend to de-emphasize capacity payments as demand response grows, coupled with PJM's and the Commission's continuing obligation to re-evaluate market mechanisms as markets mature, provides sufficient insurance against the ossification of constructs that have outlived their utility. Finally, PJM is concerned that providing triggers of the kind some have suggested would introduce a level of uncertainty into the market that would discourage the very investment that RPM is intended to stimulate.

C. *Seasonal Auctions*

In response in part to concerns about the impact of RPM on the price signals for demand responders, PJM has added seasonal pricing to the RPM proposal. Specifically, when PJM conducts an RPM auction for a given year, PJM will calculate separate clearing prices for each of the four seasons in that year. Sellers of generation resources will be allowed to offer their resources at prices that vary by season; moreover, while an LSE's overall annual capacity obligation will not change, the LSE could meet its obligation in part with individual resources that are available only for a season. Similarly, sellers of demand resources will have the option of offering their resources for the full year or for the summer (peak-load) season. As explained by Mr. Ott, seasonal pricing should enhance efficiency, opening opportunities for competition from resources (such as generation resources outside PJM) that may not be available to PJM loads year-round.

D. *Changes to the Variable Resource Requirement Curve*

PJM recognizes the importance of designing a VRR curve that optimizes the trade-off between cost and reliability. That is why PJM has devoted considerable resources to assessing different curves and testing their expected performance with dynamic economic modeling, as explained by Professor Hobbs in his affidavit. In response to concerns expressed by load interests, PJM has refined its analysis to ensure that capacity payments are minimized while still meeting reliability requirements. Based on additional analysis which shows that reliability will not be compromised, PJM adopted a change to the VRR curve (suggested earlier this year by load-serving interests) that moves the point on the curve at which the capacity price goes to zero from the IRM plus 10% to IRM + 5%. Among other effects, this curve should reduce the costs to load when the auction clears at capacity levels above the IRM, and should help ease the transition from the current vertical demand curve to a downward-sloping VRR curve.

PJM also recognizes that the selection of the VRR curve involves a balancing of cost, reliability, and other factors. Throughout the development of RPM, PJM has continually reviewed and refined the VRR curve in response to stakeholder input and additional analysis. PJM does not view that process as ending with this filing. The submitted RPM tariff provisions specify a stakeholder process to review the initial curve shape and parameters within three years after RPM is implemented. Even before that deadline, however, PJM expects and welcomes constructive analysis from the states and other stakeholders to help ensure that, when it comes to this important determinant of capacity pricing, this region gets it right.

E. *RTEP Solution When New Generation/Demand Resource Solutions are not Forthcoming*

RPM's locational capacity pricing is designed to incent new generators, new demand resources, or new merchant transmission projects to resolve potential local deliverability issues before they arise. However, if higher locational prices do not prompt new entry in a particular area, PJM will act to ensure that loads in the affected zone do not indefinitely pay higher capacity prices. If, for whatever reason, a generation or demand response solution is not forthcoming after PJM has conducted the initial auctions for two successive delivery years, then PJM will investigate in the RTEP process the costs and benefits of a transmission upgrade that would relieve constraints on deliveries into that zone. If the transmission upgrade is beneficial (comparing its cost against the benefits of eliminating the locational premium into the zone), PJM will direct that the upgrade be built through the RTEP process.

F. *Load Management Initiatives*

PJM has heard from many stakeholders that market rules should be changed where practicable to allow demand resources to compete on equal terms with generation. Consistent with this philosophy, RPM allows load management capability to be submitted in the auction as a competitive capacity resource, much like generation resources.

Moreover, PJM is working with stakeholders to deliver further improvements to the PJM load management programs in the near future, including creating a forward-energy reserve product; using load-reduction capability to meet some of the system's ancillary service needs, as well as its energy needs; and expanding the contributions of load management during emergencies. These changes will complement the capacity-market opportunities that RPM offers for demand resources, and also provide the foundation for their expanded market participation.

However, as with the RTEP reforms discussed above, RPM should not be delayed to consider the load management changes. Rather, the two initiatives (RPM and the load management changes) are complementary.

G. *Flexible Self-Scheduling*

Under RPM, LSEs will have the option to specify their self-owned generation or unit-specific bilateral contracts to hedge their reliability charges under RPM. LSEs that "self-schedule" will enter their owned or contracted resources into the auction at a zero-price bid (i.e., the LSE will be a price-taker), and then the auction will procure any remaining capacity required for the region. During the Delivery Year, LSEs with self-supply or bilateral contracts will receive revenue credits based on the capacity of their resources and the clearing prices established in the auction. For various reasons (as discussed by Mr. Ott at page 14 of his affidavit), however, there is a possibility that the RPM revenues a self-scheduling LSE will receive by virtue of its capacity resources will not completely offset the RPM charges the LSE will incur on behalf of its loads.

In response to stakeholder concerns regarding this issue, PJM added a "flexible self-scheduling" option to RPM. This option allows an LSE to designate a resource as self-scheduled to the extent needed to meet the capacity charges attributable to its loads, while also specifying a selling price to offer the resource into the auctions to the extent it is not needed to meet the LSE's reliability charge obligations. In this way, an LSE can designate an additional amount of capacity to cover its loads, as protection against RPM charges, but will not lose the opportunity to offer that capacity into the market, to the extent the capacity turns out to be in excess of that needed to cover its RPM obligations.

H. Capacity Resource Plan Alternative

At the June 16, 2005 technical conference on PJM capacity markets, the representative of American Electric Power ("AEP") argued that LSEs should be allowed an alternative to participation in RPM. AEP recommended that LSEs should be allowed to identify to PJM, four years in advance, sufficient generation capacity to meet a pre-determined fixed capacity requirement. PJM then would remove the LSE's load from the regional load obligation satisfied through RPM, and the LSE would avoid the locational reliability charges otherwise applicable under RPM.

To address this concern, and advance the Commission's consideration of this issue, PJM prepared draft business rules, appended to this filing at Tab A, embodying an alternative along the lines of that suggested by AEP. As detailed in the business rules, an LSE electing this alternative would submit to PJM each year a Capacity Resource Plan covering the next five years including the RPM Delivery Year, designating the load to be covered, the unit-specific generation resources needed to cover the capacity requirement for such load, and any transmission upgrades needed to ensure that the generation is deliverable to the load. If the load is located in a constrained Locational Deliverabality

Area ("LDA"), an appropriate percentage (specified by PJM in advance each year) of its generation resources also must be located in that LDA.

The participating LSE's fixed capacity requirement would equal the installed reserve margin then in effect for the PJM region, plus a specified additional margin to cover the uncertainty associated with forward commitment, and to ensure that an LSE electing this alternative contributes equivalent installed generation to the market as the LSEs participating in RPM.[13] So long as it fulfills the commitment in its Capacity Resource Plan,[14] the LSE would avoid the RPM Locational Reliability Charge otherwise applicable to the load it designated under the plan. The participating LSE's load would not be used in calculating the RPM capacity requirement.

PJM developed this alternative in a form that would permit its integration into RPM—for the Commission's consideration, but has not included it in the tariff sheets submitted with this filing. Some stakeholders have expressed opposition to AEP's proposal, and PJM recognizes concerns that this type of modification could undercut the objectives of RPM. In particular, it is vital that the rules under which LSEs could participate in this alternative must protect all other LSEs from potential market manipulation. PJM believes that the business rules in Attachment A would provide sufficient protection for the market; however, the Commission must be extremely cautious in making any additional accommodations in such rules.[15] For example, it is important that participating LSEs include their entire load obligation under the Capacity Resource Plan. Partial participation (with part of an LSE's load under RPM and part

---

13 Under the attached draft business rules, the reserve margin uncertainty factor would be 3.0%. One percent of this factor corresponds to the 1.0% offset to IRM in the VRR curve adopted for RPM; the remainder quantifies four-year-ahead load forecast uncertainty.

14 Resources designated in the plan cannot be offered into any RPM auction or receive any RPM capacity revenues, since they already are committed to meeting the participating LSE's capacity obligations. Participating LSEs that do not honor their commitments would face a substantial charge for non-compliance.

15 Even if the Commission adopted the attached alternative with no changes, close monitoring would be needed. If a large number of LSEs participated, and there were significant non-compliance with the capacity commitments made by LSEs in their Capacity Resource Plans, then PJM would need to revisit this option.

under this alternative), would be contrary to the purpose for which this alternative is offered, could present gaming opportunities, and could open this alternative to many more LSEs than is warranted by its narrow purpose (i.e., LSEs operating in a fully regulated state). This in turn could cause a substantial reduction in the value of capacity in the RPM auctions at levels above the reserve margin used in this alternative. To the extent this happens, the benefits of a downwardly sloped VRR curve –including greater revenue stability and reduced incentives for generators to exercise market power in the capacity market- could be significantly reduced.

Despite these concerns, PJM is including a detailed exposition of this alternative in the initial RPM filing, so that the Commission will have the benefit of comments both in support and in opposition—from the interventions in this proceeding, and can reach its own conclusions concerning the merits of such an alternative.

I. *Alternatives to RPM*

At the June 16, 2005 technical conference on capacity markets in PJM, the Commission heard two alternative proposals to RPM. A coalition of consumer advocates, industrial customers, and wholesale customers presented their Enhanced Integrated Transmission and Capacity Construct ("EITCC") proposal, and PPL Corporation ("PPL") presented an alternative that emphasizes reliance on the bilateral market.

These proposals have much in common with PJM's proposal. PPL supports RPM's locational capacity aspects, the use of a downward-sloping demand curve, and setting capacity obligations four years in advance. Similarly, the group sponsoring the EITCC proposal (the "EITCC Coalition") recognize that the current capacity construct lacks a needed locational element. Moreover, a primary focus of the EITCC proposal is reform of the RTEP process, to extend the planning horizon, assess at-risk generation, and enhance economic planning. As described above, PJM already is pursuing such reforms. The EITCC proposal also encourages demand response reforms such as those PJM plans to file soon.

Where there are differences between the proposals, however, they are significant. PJM here highlights three of the most important. First, both the EITCC Coalition and

PPL advocate reliance on voluntary bilateral markets, with mandatory auctions for a final matching of capacity obligations and resources a few months before the Delivery Year. Second, while it recognizes the need for locational capacity requirements, the EITCC proposal's Locational Market Areas are relatively large, and are not based directly on the RTEP deliverablity analyses. Third, although PPL supports a downward-sloping VRR curve, the EITCC Coalition wishes to retain the single-value capacity deficiency rate, i.e., the vertical demand curve. PJM has significant concerns with each of these major differences.

1. Forward Capacity Commitment

As Mr. Ott explains in his affidavit, the voluntary forward capacity market proposals will not achieve the same objectives as the four-year forward RPM proposal, because reliability constraints must be satisfied for the entire system on a forward basis. The capacity construct should be designed to serve the long-term reliability requirements of the system, i.e., both adequate generation supply and adequate transmission deliverability to each region of the market. A voluntary forward market would not require LSEs to arrange to cover their entire load obligation until the short-term residual auction is held, which is only a few months before the Delivery Year in both the EITCC and PPL proposals. This type of voluntary forward market is essentially what exists in PJM today, with the option but not the obligation to contract forward for capacity. As has been experienced to date, this approach creates fundamental inconsistencies between forward market results and reliability requirements.

For example, under a voluntary forward market, it is likely that only a portion of the total load would elect to participate; consequently, there is significant risk that critical generation in a constrained LDA would not be contracted by load on a forward basis. This could result in the same short-term crisis scenarios experienced under the current capacity construct. As PJM has seen, such near-term reliability problems require out-of-market generator deactivation contracts that distort forward market investment signals, and thus adversely impact investment. As Mr. Ott states, "[s]ince reliability requirements are based on ensuring that all firm load is served, it is imperative that the forward market contains all of the firm load so that the market results accurately reflect all of the reliability constraints."[16]

In short, these alternatives leave uncertain whether there will be sufficient resources to meet load in the Delivery Year. If the previously committed bilateral resources are below the level needed to meet loads, there will not be sufficient time to make alternative arrangements, and reliability issues will arise. In this respect the alternative proposals that rely on voluntary commitments suggest a different balance between near-term cost and the degree of certainty of sufficient resources for reliability, in effect giving greater weight to the former. The commitment to ensuring system reliability precludes PJM from recommending a similar choice.

2. Locational Reliability

There is general agreement that the capacity market should have a locational aspect, recognizing that even when the overall region has sufficient reserves, reliability issues still may arise in subregions, because capacity was not installed in the locations where it is needed. While the EITCC proposal recognizes this principle, its view of the relevant locations is flawed. Under the EITCC proposal, there would be only two "local market areas," i.e., Eastern MAAC and Southwestern MAAC.

As explained by Mr. Herling in his affidavit, PJM identifies deliverability constraints for a wide range of load areas through its planning process, including individual transmission owner service territories, sub-zones in such territories, and large regions comprised of multiple service territories. When PJM finds that one of these areas fails the deliverability test, the available transmission solution that resolves that reliability violation will be the upgrade that addresses the particular constraint limiting deliverability to that particular area. Similarly, the effective generation solution will be a plant located within that particular area, thereby effectively mooting the transmission constraint that is limiting deliveries into that area.

Accordingly, the capacity areas used in RPM must be consistent with the areas found by the transmission planning process to have deliverability issues. If the areas are

[16] Ott Affidavit at 16.

not consistent, then generation sited in response to elevated locational capacity prices might not resolve the deliverability problem that resulted in the elevated capacity price. Generators would receive the higher capacity prices, but a transmission solution still would be needed. For example, if a locational capacity market paid higher prices in all of the eastern PJM region, but the deliverability problem was in northern New Jersey, then generation added on the Delmarva Peninsula would receive the higher price, but would not solve the problem in New Jersey. While larger LDAs may have a role in a relatively short transition that phases in the full locational requirements, the proposal should not include on an open-ended basis market areas that do not correspond to the deliverability areas assessed in the planning process.

3. Variable Resource Requirement Curve

As PJM understands their position, most, if not all of the EITCC Coalition is fundamentally opposed to a downward-sloping VRR curve. However, PJM's current capacity mechanism already uses an administratively determined vertical demand curve. So long as a separate capacity market is required, and so long as all load must be covered by that capacity requirement, the need to set a price for meeting that requirement will remain. The real difference on this point between the RPM and EITCC approaches is the shape and placement of that price curve.

RPM uses a downward sloping VRR curve, similar to the demand curve approved by the Commission for the NYISO and approved in principle for ISO-New England L.L.C ("ISO-NE"). Based (as is today's capacity deficiency rate) on the cost of adding a new combustion turbine plant to the system, the VRR curve establishes higher (scarcity) prices for critical shortages, and decreasing prices when resource levels exceed the IRM. The recognition of some value to capacity above the IRM dampens price volatility, making estimates of future prices more reliable and allowing investors to make reasonable predictions of revenue streams. Simulations have shown that this concept reduces reserve and capacity price volatility and consequently the return required by investors resulting in savings in consumer costs.

Extensive studies (as discussed by Professor Hobbs) show that additional reserves due to the VRR curve result in lower capacity and energy costs to consumers. Excess reserves also further reduce the probability of loss of load and discourage withholding by suppliers to increase profits.

In contrast, the extensive studies performed for PJM show that reliance on bilateral markets coupled with high deficiency charges to load (which in effect create a vertical demand curve) are over time more costly because they are unlikely to produce the investment required in a timely manner.

III. THE COMMISSION ALREADY HAS APPROVED FOR OTHER RTOs MOST OF THE CRITICAL ELEMENTS OF RPM

RPM is well-grounded in Commission precedent. RPM preserves the basic structure of PJM's existing capacity rules—requiring LSEs to commit their owned or contracted resources or pay a deficiency charge— and adds elements locational pricing and a downward-sloping resource requirement curve – that the Commission recently has approved for other regional energy markets.

A. *RPM Retains the Essential Capacity Commitment/Deficiency Charge Structure Previously Approved by the Commission*

PJM long has relied on reliability adequacy rules that require LSEs to commit capacity to support service to their loads, or pay a deficiency charge based on the fixed costs of a new generator.[17] When it approved PJM as an independent system operator,

---

17 Pennsylvania-New Jersey-Maryland Interconnection, 81 FERC ¶ 61,257, at 62,275 (1997) ("PJM ISO Order"), reh'g denied, 92 FERC ¶ 61,282 (2000). As described by the Commission, before PJM became an ISO, the PJM power pool developed procedures that:

> (1) determin[e] the pool-wide generation requirement needed to meet pool-wide loads, including reserves; (2) determin[e] each member's individual obligation to contribute to the pool-wide generation requirement; (3) measur[e] each member's compliance with its obligation; and (4) develop[ ] charges that apply whenever a member fails to meet its individual obligation (referred to as a capacity deficiency).

the Commission found that these rules have "generated significant reliability and cost-saving benefits for the PJM members over the years,"[18] and extended them beyond the original participating utilities through a "contractual requirement for LSEs to participate in long-term reliability."[19] Each time a new control area has been integrated into the PJM region, the Commission has reaffirmed the need for a capacity commitment structure to support the wholesale energy market and the reliability of service to all loads in the PJM region.[20]

RPM preserves that fundamental capacity commitment structure, but adds new features to address the deficiencies highlighted above, i.e., the failure to recognize locational differences in the value of capacity, the "vertical" demand curve resulting from the current single deficiency charge, the short-term nature of the current capacity commitment, and inadequate opportunities for participation by planned generation resources, planned or existing demand resources, and planned transmission upgrades.

While RPM, for the first time, comprehensively integrates solutions to these problems, the elements added by this filing are not new to the Commission, having been

---

As the Commission explained, "the capacity deficiency charge . . . is based on the cost of installing a combustion turbine generator." PJM ISO Order, 81 FERC at 61,276, n. 197

18 PJM ISO Order, 81 FERC at 62,275.

19 Id. at 62,277.

20 PJM Interconnection, L.L.C., 106 FERC ¶ 61,253, at P 45 (2004) (recognizing that preexisting reserve rules in the Commonwealth Edison control area ("NICA") cannot be maintained because they "do not provide the individual LSE commitments and specific resource identification needed for loads in NICA to participate in the PJM market on the same basis as other LSEs in PJM"); PJM Interconnection, L.L.C., 108 FERC ¶ 61,318, at PP 51-54 & n.49 (2004) (application of West RAA to existing generators and all LSEs in the AEP and DP&L control areas); See also PJM Interconnection, L.L.C., 103 FERC ¶ 61,250, at 61,934 (2003) (accepting filing to implement common unforced capacity approach throughout PJM, finding that "[a] single capacity market will create the same rules and incentives for all customers"), PJM Interconnection, L.L.C., 96 FERC ¶ 61,060, at 61,213-14 (2001) (generally approving filing "designed to make reliability rules for PJM West compatible with the rest of PJM; thus precluding one area from unfairly 'leaning' on the other").

approved repeatedly for other system operators. In the last two years, the Commission has issued numerous orders reforming the reliability adequacy rules for the two independent system operators to PJM's north, the NYISO and ISO-NE. Through those orders, the Commission already has approved, or accepted in principle: downward-sloping resource requirement curves; locational differences in capacity prices; and market-based capacity pricing approaches as a preferred long-term replacement for "reliability must run" contracts.[21] Moreover, the other notable feature of RPM-- securing capacity commitments several years in advance --is not new either, as from 1974 to 1999 PJM required LSEs to commit their resources two years in advance.

B. *The Commission Already has Accepted Downward-Sloping Capacity Price Curves of the Type Proposed in RPM, and the Court of Appeals has Affirmed that Decision*

In 2003, the Commission approved the NYISO's proposal to replace its single capacity deficiency charge with a downward-sloping curve, relating varying capacity prices with varying capacity levels,[22] finding "the ICAP Demand Curve to be an

---

21 An initial decision in the ISO-NE proceeding strongly affirmed the ISO's proposal on most of the remaining detailed issues that were set for hearing in that case. See Devon Power LLC, 111 FERC ¶ 63,063 (2005). Although the Commission recently agreed to defer the effective date of the ISO-NE capacity market and hold oral argument on exceptions to the initial decision, the Commission noted again that it already has accepted the two broad concepts of locational pricing and the use of a demand curve as just and reasonable. See Devon Power LLC, 112 FERC ¶ 61,179, at P 1 (2005).

22 As explained by the Commission in a later order:

> Demand Curves serve to define the amount of ICAP that each load serving entity (LSE) would have to obtain for the following month. They were intended to improve system and resource reliability by valuing the ICAP resources available above the system's required levels, and providing more effective economic signals for new investment.

N.Y. Indep. Sys. Operator, Inc., 110 FERC ¶ 61,201, at P 7 (2005).

appropriate new tool in providing reliable service to customers."[23] The Commission found that the NYISO capacity market previously experienced "extreme price differentials" around the IRM established in the reliability planning process, and concluded that the NYISO's proposed resource-curve approach is "a rational way" to satisfy that required IRM "over the long term."[24] The Commission found that a downward-sloping curve would "reduce[e] price volatility" yielding "substantial benefits" including "a more stable and predictable ICAP revenue stream [that] would reduce the risk to generation investors, and thus reduce the cost of financing new investment."[25] The Commission expects "that customers would share in this cost reduction." Id.[26]

On review, the court of appeals turned aside all objections to the Commission's approval of the NYISO demand curve, accepting the Commission's view that "stable ICAP revenues will reduce the risk and cost of financing investment in new generation capacity and thus reduce the cost of electricity to consumers in the long term."[27]

A demand-curve approach therefore has been in effect in New York for two years, and the NYISO reports that it is performing as expected, contributing to more stable capacity prices and commitment of more capacity to that market.[28] Consistent with

---

23 N.Y. Indep. Sys. Operator, Inc., 105 FERC ¶ 61,108, at P 39 (2003) aff'd, Elec. Consumers Res. Council v. FERC, 407 F.3d 1232 (D.C. Cir. 2005) ("ELCON"). The NYISO and the Commission referred to this curve as a "demand curve." In RPM, PJM refers to the same type of curve as a "variable resource requirement curve" or "VRR Curve."

24 Id. at P 42.

25 Id. at P 29.

26 The Commission found no reason to reject the proposed curve "based strictly on whether it is set administratively," explaining that "[t]he issue is whether the proposed administrative approach (like the existing administrative approach) is 'just and reasonable.'" Id. at P 36.

27 ELCON, 407 F.3d at 1238.

28 See NYISO's Second Annual Compliance Report on Implementation of the ICAP Demand Curve and Withholding Behavior Under the ICAP Demand Curve," Docket No. ER03-647-006, at 1 (Dec. 2, 2004).

earlier commitments, the NYISO filed recently to set the parameters of its ICAP demand curves for its next three planning years, including such elements as the cost of new entry, revenue offset, and curve shape, which are the same types of parameters used to set the VRR curve in RPM.[29] The Commission accepted the filing, noted that issues were raised that required further development, but did not find any need for a full hearing on the filing. Instead, the Commission directed its staff to convene a technical conference and gather additional on-the-record information so the Commission could decide all issues raised. Id. at P 28.

The Commission also has approved, in principle, ISO-NE's use of a capacity demand curve. In response to a series of RMR contracts filed for the ISO-NE market, the Commission found, under FPA § 206, that the ISO-NE market rules did not adequately compensate generators needed for reliability, and ordered ISO-NE to file long-term reforms. ISO-NE responded by filing a locational capacity pricing proposal that includes a demand curve. The Commission accepted ISO-NE's filing, "preliminarily find[ing] the use of ICAP regions and an ICAP demand curve as proposed by ISO-NE to be just and reasonable," setting only some of the specific details of the proposal for hearing.[30] In generally accepting a downward-sloping demand curve, the Commission found it "a just and reasonable approach to address the compensation issues plaguing the current ICAP market," that has merit "because it would eliminate seams between ISO-NE and the NYISO," provide appropriate locational price signals, and "properly account for constraints on the transmission system and reduce price volatility."[31] While it set the details for hearing, the Commission stated that it would not entertain alternatives to a

---

[29] N.Y. Indep. Sys. Operator, Inc., 110 FERC ¶ 61,201, at PP 19-22 (2005).

[30] See 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 P 14 (2005) ("Devon III").

[31] Devon III, 110 FERC at P 17.

sloped demand curve approach in the proceeding.[32] Thus, the VRR curve PJM proposes here follows the New York and New England precedent in using a downward-sloping resource requirement (or demand) curve that relates the value of capacity to the amount of capacity available.

C. *The Commission Already has Accepted Locational Capacity Pricing of the Type Proposed in RPM*

In its reliability compensation policy, established in a PJM proceeding, the Commission found that "features such as locational requirements for installed capacity may prove an effective approach to create stable revenue streams."[33] Applying this policy, the Commission has approved locational capacity pricing for both the NYISO[34] and ISO-NE.

For ISO-NE, the Commission found locational capacity pricing just and reasonable because it:

1) provides price signals to encourage investment that results in generation additions and improved reliability; and

2) values capacity in a way that accounts for the transfer limits of the transmission system.[35]

Finding that "the primary purpose of the [locational capacity] mechanism is to ensure that capacity resources are appropriately valued based on their location so that the

---

[32] Devon II, 109 FERC at P 24. The Commission also rejected arguments that a demand curve "sets a floor price," finding that "[u]nder the general concept of a demand curve . . . the price for ICAP resources will move lower or higher depending on the capacity situation" resulting in "a specific price point in the event of a specific capacity situation" rather than "any 'floor price.'" Devon III, 110 FERC at P 21.

[33] PJM Interconnection, L.L.C., 107 FERC ¶ 61,112, at P 20 (2004).

[34] See N.Y. Indep. Sys. Operator, Inc., 105 FERC ¶61,108 (2003).

[35] Devon II, 109 FERC at P 24.

resources remain in operation," the Commission concluded that "[a]ppropriately valuing capacity resources ensures that they are adequately compensated, and higher prices in a given region will also reflect the need for investment and demand response in that area."[36] The Commission found that locational pricing was warranted because "[t]he current ICAP regime has produced prices for ICAP that do not compensate a number of generators" in the most capacity constrained subregion in New England; "some of these generators have filed for RMR agreements;" and "there are virtually no generation additions currently planned for installation between 2005 and 2008" in that subregion.[37]

Based on these facts, the Commission concluded "it is vital that existing generation receive the appropriate capacity payments" because adequate compensation provides "an incentive to remain in operation and to avoid retirement or applying for out-of-market cost of service RMR contracts." Id. The Commission concluded that locational pricing was required, even though it had not found such pricing would result "in the immediate addition of generation" in constrained areas. Id. at P 15. Moreover, such pricing was required even though proposed transmission upgrades "may provide immediate relief" for capacity shortages, because "peak load will continue to grow over time," and "[i]f price differentials re-emerge, even due to temporary issues such as outages," locational capacity pricing "will be helpful in assigning costs to the appropriate customers." Id. at P 17. Moreover, higher locational capacity prices in constrained areas "will encourage planned transmission upgrades to be completed promptly." Id. at P 15.[38]

---

36 Devon Power LLC, 110 FERC ¶ 61,313, at P 23 (2005) ("Devon IV"). The Commission expressly rejected assertions that locational pricing is not needed because reserve levels in the New England subregions exceed "accepted reliability standards," responding that the Commission "is not establishing minimum reliability criteria in this proceeding . . . and whether the capacity surpluses in each area meet or exceed reliability standards is not relevant in our analysis in this proceeding." Id.

37 Id. at P 13.

38 The Commission also rejected arguments that lower-cost units in a constrained area should not receive higher payments based on the costs of a new unit, stating that "under the LICAP mechanism, all generators in a LICAP region that are accepted in a LICAP auction at a given time should receive the same price." Devon III, 109 FERC at P 44.

D. *The Commission Already has Found that Market Solutions Should be Implemented as a Long-Term Alternative to Disfavored RMR Contracts*

The Commission has found that "use of RMR agreements to keep units needed for reliability in operation [is] not in the best interests of the competitive markets because they tend to raise prices, affect the operation of other suppliers and impact on the ability of new generators to enter the market."[39] As to ISO-NE, the Commission directed that, rather than RMR, the New England market "should implement a market-based mechanism . . . that appropriately values capacity according to location and does not limit the ability of other generators to earn competitive revenues."[40] Such agreements should "not proliferate" and should be used "strictly as a last resort so that units needed for reliability receive reasonable compensation." Id. at P 40.

IV. PJM'S EXISTING CAPACITY PRICING AND CAPACITY MARKET RULES ARE NO LONGER JUST AND REASONABLE AND MUST BE REFORMED

A. *PJM'S Authority to Make This Filing*

The PJM Board is authorized to amend the East RAA,[41] West RAA,[42] South RAA,[43] and the PJM Tariff provisions at issue here,[44] through filings with the

[39] Devon IV, 110 FERC at P 3, citing Devon I, 107 FERC at PP 27-32.

[40] Id. at P 20. See also PJM Interconnection, 107 FERC at P 20 (making market design improvements "is the preferred choice for resolving material Reliability Compensation Issues.")

[41] See East RAA § 16.4, see also PJM Interconnection, L.L.C., 96 FERC ¶ 61,061, at 61,229-30 (2001) (mandating that the PJM Board be given exclusive authority to amend the East RAA).

[42] See West RAA § 17.4, see also PJM Interconnection, L.L.C., 96 FERC ¶ 61,060, at 61,211 (2001) (mandating that the PJM Board be given exclusive authority to amend the West RAA).

[43] See South RAA § 16.5.

Commission under FPA section 205. Although PJM may amend the Operating Agreement under section 205 only upon a supermajority sector vote of the PJM Members Committee, which (as discussed below) was not received, the PJM Board may direct the filing of changes to the Operating Agreement under FPA section 206.[45]

Virtually all of the substantive provisions at issue in this filing are contained in the RAAs and the PJM Tariff, over which PJM has section 205 authority. The current RAAs (under the Board's section 205 authority) set forth the detailed requirements and formulas to determine the capacity obligations of LSEs, the timing for meeting those obligations (i.e., seasonal intervals of the current planning period), the region-wide (i.e., non-locational) scope of those obligations, the standards and procedures for qualifying resources as capacity resources, and the charges for failure to obtain sufficient capacity (i.e., the current flawed "vertical" demand curve) or for failure to honor prior commitments of capacity resources or load management capability. PJM proposes to place the RPM version of most of these provisions in the new consolidated RAA (over which the PJM Board will have section 205 authority), but transfer some of them to the PJM Tariff, which also is under the Board's section 205 authority. In addition, PJM proposes to place in the PJM Tariff the remaining RPM provisions, including auction rules, market power mitigation rules, transition provisions, reliability backstop rules, and credit rules. Placing these RPM provisions in the PJM Tariff, and subject to PJM's section 205 rights, is reasonable, as most of the current corresponding provisions appear in the RAAs or PJM Tariff (under PJM's section 205 authority). Moreover, all of these RPM provisions are concerned with preserving the reliability of the PJM Region, which is a core responsibility of the PJM Board,[46] and which the Commission held must be

---

[44] See PJM Tariff § 9.2(a).

[45] See Operating Agreement § 7.7(vi).

[46] See Operating Agreement, § 7.7(vii).

under the Board's section 205 authority to ensure PJM's independence as a regional transmission organization.[47]

As explained in section VI of this transmittal, the Operating Agreement changes, being filed under section 206, merely involve terminology changes to reflect the consolidation of the East RAA, West RAA, and South RAA, which the Commission already has indicated the parties should accomplish;[48] clarifying changes to reflect that existing operational responsibilities of "Capacity Resources" in the Operating Agreement refer to generating units; non-substantive replacement of several cross-references to the term "ALM," with the equivalent term under RPM, "ILR;" and the elimination, as mooted by RPM, of the existing daily and monthly capacity credit markets. While this last change has substantive significance, there also is little doubt, as shown in section IV.C.2.e below, that the current short-term capacity credit market is deeply flawed, with volatile pricing, no long-term signals, and no means whatsoever to help manage or prevent potentially disruptive generation retirements. Moreover, it is not just and reasonable for one element of the current capacity adequacy construct, i.e., the capacity credit market rules, to be maintained in an agreement (the Operating Agreement) over which the PJM Board does not have section 205 authority. As the Commission has found, the PJM Board should have authority over all reliability matters, and reliability pricing should be no exception.

Nonetheless, whether considered under section 205 or section 206, the changes are warranted. This filing demonstrates that all of the aspects of the PJM reliability adequacy construct sought to be changed here (regardless of the agreement in which found) have become unjust and unreasonable and must be replaced with the proposed just and reasonable substitute, RPM. The existing construct has become ineffective, and must be replaced, to ensure that reliability will continue to be preserved in the future.

---

47 See PJM Interconnection, 96 FERC ¶ 61,061, at 61,229-30; PJM Interconnection, 96 FERC ¶ 61,060, at 61,211.

48 See PJM Interconnection, L.L.C., 109 FERC ¶ 61,012, at P 63 (2004).

B. *Legal Standards Under FPA §§ 205 and 206*

Under both sections 205 and 206, PJM must demonstrate that the changes proposed in this filing are "just and reasonable." Section 206 adds the requirement that PJM show that the current capacity pricing and capacity market rules on file with the Commission are "unjust, unreasonable, unduly discriminatory or preferential." 16 U.S.C. §§ 824d and 824e(a). What is just and reasonable is not merely the lowest rate to consumers, but the lowest reasonable rate that provides adequate assurance that suppliers will make the capital investments needed to meet reliably the needs of consumers.

In assessing whether rates, terms, or conditions are just and reasonable, the Commission may act within a "zone of reasonableness." That broad zone "is delineated by striking a fair balance between the financial interests of the regulated company and the relevant public interests."[49] As the courts have recognized, "[a] primary purpose of the Federal Power Act . . . was to encourage the orderly development of plentiful supplies of electricity and natural gas at reasonable prices."[50] In the electric utility context, this means the preservation of adequacy and reliability of service. Establishing tariffs that maintain adequate and reliable service (both through rates and through terms and conditions of service) is fundamental under the FPA.

Various factors, including continued limited demand-side response under retail regulatory frameworks, currently preclude reliance solely on a competitive wholesale energy market to ensure reliability, and require a continuation of a wholesale capacity commitment requirement. As shown in this filing, PJM's existing capacity pricing and capacity market rules no longer provide sufficient assurance that the FPA objectives of long-term reliability at lowest reasonable cost will be met. Accordingly, RPM builds on and preserves much of the existing capacity commitment requirement, but addresses and resolves the deficiencies in its pricing and market rules in a comprehensive manner.

---

49 Farmers Union Cent. Exch., Inc. v. FERC, 734 F.2d 1486, 1502 (D.C. Cir. 1984) ("Farmers Union")(internal quotations and citations omitted).

50 Pub. Utils. Comm'n of Cal. v. FERC, 367 F.3d 925, 929 (D.C. Cir. 2004) ("CPUC") (internal quotations and citations omitted).

Notably, the Commission already has found under FPA § 206 that capacity compensation approaches like PJM's existing rules are not just and reasonable because they do not provide sufficient or stable revenues to compensate generators needed for reliability.[51] Moreover, the Commission has found that out-of-market agreements to continue such units in service—so-called RMR agreements– also are not a reasonable long-term solution. The Commission has endorsed use of a downward sloped demand curve in locational capacity auctions as a necessary substitute for pre-existing vertical demand curve approaches, and was affirmed by the court in ELCON. Id. at P 58.[52]

As the court held in ELCON, a downward-sloping curve, such as the VRR curve proposed here, is not an "incentive rate" subject to a higher standard of proof or review. In the court's view, the "most important" factor in that distinction was that "unlike incentive ratemaking, the ICAP Demand Curve encourages investment in new generation capacity by ensuring increased stability in ICAP revenues, not higher rates across the board."[53] Similarly, rather than "granting above-cost premiums to suppliers of capacity," a downward-sloping VRR curve restructures capacity prices "to more realistically reflect the economic value of capacity reserves and to send better price signals to encourage the construction of generation before a shortage occurs." Id. at 1237-38 (internal quotation marks omitted).

As shown in this filing, the Commission's and the court's conclusions in these earlier cases apply equally here.

C. *PJM's Existing Capacity Pricing and Market Rules No Longer Provide Adequate Assurance that Sufficient Capacity Will be Built or Maintained to Meet the Region's Long-term Needs at the Lowest Reasonable Cost*

1. Description of Current Construct

[51] Devon I, 107 FERC at P 30 (2004).

[52] See N. Y. Indep. Sys. Operator, Inc., 105 FERC at P 39.

[53] ELCON, 407 F.3d at 1237 (internal quotation marks omitted).

Mr. Herling briefly describes in his affidavit the evolution of the existing capacity adequacy rules in PJM. As he explains, utilities and power pools (and more recently, ISOs and RTOs) long have abided by well-established criteria to quantify adequate installed generation capacity. The loss of load expectation ("LOLE") measure is a common industry criterion used to establish capacity requirements, and is the basis for PJM's installed capacity requirement. The LOLE is a measure of the likelihood that system demand will exceed the available generation capacity; in PJM and elsewhere, the LOLE goal is for demand to exceed capacity no more than one day in ten years. The installed capacity ("ICAP") required to meet this criterion is expressed in terms of a percent reserve above the forecast peak load. Since the 1960's, PJM has been using probabilistic methods[54] and the established one-day-in-ten-years LOLE to determine the reserve requirement for the area served by PJM.[55]

In addition to the region-wide generation adequacy standard, PJM has long used a deliverability standard to test the system's ability to deliver energy from and to various parts of the region. As Mr. Herling explains, PJM evaluates both generation deliverability and load deliverability.[56] Generation deliverability refers to the capability of the system to deliver excess energy from a cluster of generators experiencing higher than normal availability to the remainder of the system experiencing a distributed shortage of capacity. Load deliverability refers to the system's capability to deliver energy from the aggregate of all capacity resources to an electrical area experiencing a capacity deficiency. As with generation adequacy, the load deliverability test employs probabilistic techniques and an LOLE standard.

As Mr. Herling explains, from 1974 to 1999, the PJM power pool imposed a two-year-forward capacity obligation. Id. The total capacity requirement for the pool was

---

54 For decades, PJM has used probabilistic methods to determine an installed reserve requirement for the region, taking into account factors related to generation performance and load characteristics that affect reliability, such as generator forced and maintenance outage rates, load variability, load diversity, forecast uncertainty, and the availability of emergency assistance from neighboring systems.

55 Herling Affidavit, at 2-3.

56 Id. at 3.

allocated among all member utilities, and each utility was required to demonstrate that it had, or would have, sufficient installed capacity to meet its load and reserve margin obligations two years ahead of the planning year. Any utility that then failed to meet its capacity obligation was assessed a capacity deficiency rate, based on the estimated annualized cost of adding a new combustion turbine to the pool.

In 1999, PJM replaced the two-year-forward obligation with the current approach, relying on a daily capacity obligation, supplemented with daily and monthly (covering up to twelve months) capacity credit markets, to accommodate the introduction of retail access. The daily obligation structure ensured that capacity obligations associated with a particular load, i.e., a retail customer, could promptly shift from one LSE to another if that load shifted from one LSE to another as a result of retail competition. However, the LOLE criterion of one day in ten years, and the probabilistic determination of a region-wide mandatory reserve requirement, remained the same. Id. at 3-4.

In 1999, PJM also revised the construct to reflect, in both the pool-wide reserve margin and LSE capacity obligations, the unavailability of installed generation resources due to unplanned outages. This unforced capacity, or UCAP, approach, discounts installed capacity based on a measure of forced outages and unit deratings, known in PJM as "$EFOR_D$."[57]

Following the initial implementation of revised capacity rules for retail open access, as Mr. Herling explains, PJM and its stakeholders made various incremental changes to those rules. Id. at 4. For example, in an attempt to address market power and potential withholding concerns, the capacity rules were revised to incent generation owners to commit their resources to PJM for three to five month periods (as opposed to only daily).[58] The other significant change since PJM was established as an ISO (and then as an RTO) has been the integration of neighboring systems into the PJM Region. As a result of these integrations, there now are three reliability assurance agreements;[59] although they all collectively implement the same region-wide UCAP approach.

---

57 See, e.g., the East RAA at Schedule 5.1.

58 PJM Interconnection, L.L.C., 95 FERC ¶ 61,330 (2001).

59 That is, the East RAA, West RAA, and South RAA.

Notwithstanding incremental changes, since the time PJM was first established as an ISO, there have been extensive discussions of more fundamental changes to the PJM reliability adequacy rules. Section IV.C.3 below provides an overview of the history of these discussions. As also discussed in more detail below, the current reliability adequacy rules do not allow capacity obligations to be met by planned new resources, demand resources (except in a limited fashion as Active Load Management ("ALM")), or through transmission enhancements. Moreover, based on the planning assumption that the aggregate of all generation is deliverable to the aggregate of all load, capacity resources-- and their prices-- are not differentiated by location.

In summary, the current reliability adequacy rules in PJM include the following elements:

- 1 day in 10 yr LOLE standard;
- unforced capacity basis;
- all LSEs required to provide assigned share of capacity needed for pool reliability, or pay deficiency charge;
- deficiency charge based on cost of new entry by CT;
- capacity obligation tracks load-switching on daily basis;
- capacity obligation is for one day, with incentive to commit capacity for a multi-month interval;
- capacity credits can be sold by parties with excess, in daily markets and in monthly markets for any of the twelve months following the market;
- universal deliverability assumed to all loads -- no locational capacity price differences;
- no recognition of different operating characteristics of capacity resources;
- demand-side response reflected through ALM credits-- capacity resources do not include demand response resources;
- capacity resources do not include transmission upgrades;
- only existing resources can be capacity resources -- no mechanism to include planned resources.

As discussed below, several aspects of the existing construct are inadequate to ensure continued reliability.

2. Current Construct Is Not Providing an Effective Reliability/Adequacy Complement to the Wholesale Energy Market

a. Problems Are Surfacing in the Deliverability of Energy to Loads in Some Areas.

PJM's current tariff rules do not differentiate capacity prices by location. PJM assesses a single deficiency rate on LSEs that do not secure capacity, regardless of location. Similarly, all capacity resources, regardless of location, are treated and priced the same in the capacity credit markets PJM presently operates. This does not reflect the fundamental reality that the system's ability to deliver energy can vary by location.

As explained by Mr. Herling, PJM's RTEP process annually tests the adequacy of the transmission system to deliver energy from capacity resources to loads in all areas of the PJM region.[60] The RTEP process determines capacity emergency transfer objectives ("Transfer Objective") for imports into PJM zones to satisfy an LOLE, as previously stated, of 1 day in 25 years. PJM compares the forecast Transfer Objective, on a five-years-ahead basis, with the forecast capacity emergency transfer limit ("Transfer Limit"), i.e., the expected ability of the transmission system to import capacity into PJM zones under emergency conditions.[61]

If a zone fails the test, i.e., the Transfer Limit is less than the Transfer Objective, the RTEP process identifies transmission upgrades needed to increase the Transfer Limit and resolve the problem. Although new generation or demand resources also could resolve the deliverability issue, the RTEP process does not solicit such projects, nor does it establish any price signals (long-term or otherwise) to guide the developers of such projects.[62]

---

60 Herling Affidavit at 5.

61 Id.

62 Id. at 15.

Applying these tests, PJM recently experienced multiple reliability criteria violations in eastern PJM, particularly in New Jersey. Several factors affect a system's ability to meet the load deliverability test, including load growth, generation additions, and generation retirements. Steady load growth and comparatively low generation additions contributed to the recent violations, but their precipitating cause was a large number of generation retirements implemented or announced in the last two years. While PJM is taking steps to address these recent violations, the underlying trends—high load growth, comparatively few generation additions, and economic pressure for generation retirements remain. If these trends continue, reliability criteria violations will likely re-appear in New Jersey, and spread to other areas of PJM where similar conditions exist.

As explained by Mr. Herling, PJM estimates that in New Jersey load will increase by 1,950 MW between 2005 and 2010, but generation additions are not expected to keep pace. Id. at 7. In 2003 and 2004, only 51 MW of new generation was constructed in New Jersey; only 1340 MW are under construction. Id.

Similarly, load growth in the Delmarva Peninsula is projected to be 2.7% per year, or an increase of 573 MW over the next five years, but planned generation additions are minimal. Only 60 MW of generation were added on the Delmarva Peninsula in 2004; and 150 MW are being studied in the interconnection process. In the Baltimore-Washington area, only 77 MW of generation were added in 2004 and none are being studied in the interconnection process. Id., at 7.

Against this backdrop, the PJM region experienced a dramatic spike in generation retirements. From 1999 through 2002, inclusive, 274 MW of generation in the Mid-Atlantic region retired. By contrast, in the last two and a half years, 1,709 MW of generation capacity retired, and an additional 1,694 MW are proposed for retirement in the Mid-Atlantic region between 2006 and 2008. The generation owners responsible for these retirements generally have claimed that the retirements are due to the current excess of generation in PJM, and the inability of these particular units to compete economically. Id., at 8.

The Commission recently determined that PJM cannot compel the owners of units proposed for retirement to remain in service; and that such retirements may take effect upon 90 days prior notice.[63] Although the system had been found reliable in prior RTEP reports, these retirements led to the identification of reliability criteria violations for 2005 and each subsequent year in the most recent planning horizon, i.e., 2006, 2007, 2008, and 2009. Herling Affidavit, at 8. Accordingly, although these units are critical to assuring deliverability to the load in New Jersey, PJM's current capacity market rules attach no additional locational value to these units commensurate with their significance to local deliverability. Moreover, because the current capacity market rules do not require long-term capacity commitments, a system that had been found reliable in earlier RTEP analyses can experience violations of reliability criteria on relatively short notice, as the New Jersey experience demonstrates.

The trends noted above make other areas, such as Baltimore-Washington and the Delmarva Peninsula, similarly vulnerable to possible reliability violations. In fact, 101 MW of generation retired in the Baltimore area in 2003, and recent planning studies found deliverability violations for both Baltimore-Washington and the Delmarva Peninsula for 2008. Id. These violations will be resolved by planned transmission upgrades, but those are only a temporary solution. Unless additional generation is sited in these areas, further load growth or additional retirements would require more extensive and costly transmission upgrades. Moreover, any additional unanticipated retirements in either Baltimore-Washington or the Delmarva Peninsula could cause these areas to experience load deliverability violations similar to those in New Jersey. Id.

b. While PJM has Been Able to Respond to the Recent Violations, Additional Tools and Remedies are Needed.

As Mr. Herling explains, the network upgrades needed to resolve the reliability criteria violations precipitated by the recent retirements will be significant and cannot be completed before the time periods for which violations have been identified. Herling Affidavit at 9.

Consequently, to assure compliance with reliability criteria, PJM identified a number of the retiring generators that, if they remained in service, would resolve the

[63] See PJM Interconnection, L.L.C., 110 FERC ¶ 61,053 (2005); see also PJM Tariff, section 119.

reliability violations. The operators agreed to retain these units in service beyond their proposed retirement dates, subject to compensation in accordance with the generation deactivation provisions recently added to the PJM Tariff.

Retention of these units in service, along with the completion of a number of transmission upgrades, has enabled the PJM system to remain in compliance with all relevant reliability criteria for the current planning period (June 1, 2005 through May 30, 2006). However, as explained above, PJM also faces reliability criteria violations for each of the next four years. Additional transmission upgrades will be needed before each of the next four summer seasons to ensure continued compliance with reliability criteria. PJM also will need to keep the retiring generators in service for a number of years beyond 2005 to protect reliability. How long these units must be kept in service will depend on the pace of transmission construction. Id.

In part to deal with these generation retirements, PJM's RTEP process recently has had to order unprecedented levels of baseline transmission upgrades to the system. Of the more than $1 billion worth of upgrades in the most recent plan, almost 60% are baseline reliability upgrades. Of these, approximately $200 million in upgrades are needed to address reliability violations from the New Jersey retirements for the years 2005 through 2007. Id. Approximately another $300 million is estimated for the transmission upgrades needed to address retirement-related reliability violations for 2008 to 2009. PJM may also need to install a new 500 kV circuit to help deliver energy from Pennsylvania to New Jersey. If required, this upgrade is expected to cost more than $100 million. Should one more large generating unit in New Jersey retire, then the 500 kV circuit certainly will be needed, with another $100-200 million in further upgrades depending on the location of the retiring generator and the magnitude of the resulting local delivery problems. Id.

The recent plan also includes baseline transmission upgrades, costing tens of millions of dollars, needed to address load criteria violations previously identified for the Delmarva Peninsula and Baltimore-Washington area for 2008. As Mr. Herling states, if any additional generators in this area announce their retirement, additional substantial and costly transmission upgrades will be needed. Id. at 9.

In short, as Mr. Herling explains, there are no quick, easy and inexpensive transmission solutions to the reliability issues that have risen in the eastern portion of the

PJM region. If recent trends continue, with few generation additions and additional retirements, the next round of available transmission solutions will become even more challenging and expensive. This is not to prejudge whether generation or transmission solutions will be the most cost effective in resolving future reliability criteria violations. However, it does underscore that the PJM region should not rely solely on transmission solutions under the current RTEP process to address any reliability issues that may arise. Aside from their expense, there is the risk that transmission upgrades would not be built in sufficient time to avoid reliability problems. For example, construction of a new 500 kV circuit typically takes ten years or longer.

Forestalling generation retirements also is not an adequate solution to deliverability issues. The Commission recently allowed generators to receive compensation under the PJM Tariff for not deactivating if such units are needed for reliability, and pursuant to that authority, PSEG Energy Resources & Trade, L.L.C. recently filed special cost-of-service recovery rates to provide out-of-market compensation for units in New Jersey comprising a total of 836 megawatts.[64] However, such special arrangements are temporary at best and fail to provide a long-term solution to the problem. As the Commission has found, such out-of-market compensation arrangements, comparable to "reliability-must-run" contracts, are "not in the best interests of the competitive markets because they tend to raise prices, affect the operation of other suppliers and impact on the ability of new generators to enter the market."[65] As Mr. Bowring explains in his affidavit, such special arrangements fail to provide the market signal or incentive needed for other generators to propose solutions to the system's reliability issues.[66] Moreover, the units proposed for retirement typically are at or near the end of their original planned useful lives, and cannot be maintained indefinitely. And forestalling retirements does not address fundamental underlying imbalances between load growth and generation additions.

---

64 See Application of PSEG Energy Resources & Trade, L.L.C. in Docket No. ER05-644-000 (Feb. 24, 2005).

65 Devon IV, 110 FERC at P 3.

66 Bowring Affidavit at 16.

Therefore, it will take more than transmission alone to address deliverability issues in New Jersey, the Delmarva Peninsula, Baltimore-Washington, or anywhere else they may arise in the PJM region. A transmission-only solution under the current RTEP process presents risks that enough transmission may not be built fast enough to avoid reliability problems. Forestalling generation retirements is only a partial and temporary solution. Future reliability can best be assured through an integrated solution, which supplements transmission enhancements identified in the RTEP process with a system of long-term capacity price signals to encourage new capacity resources to locate in the areas of greatest need.

c. PJM's Current Construct is of the Type Prone to Boom-Bust Cycles, and Prices have been Below the Cost of Marginal Units for Several Years, Heightening Concerns About Long-Term Price Volatility and Dampened Investment.

As seen from Figure 3 above, PJM's current daily and monthly capacity credit market, with its single value capacity deficiency rate, has led to significant volatility in capacity prices.

Currently, PJM assesses a capacity deficiency charge (based on the costs to install a new combustion turbine unit) if a LSE has not obtained sufficient capacity for its loads plus a required installed reserve margin (currently 15 %). Under these pricing rules, capacity resources needed to satisfy that margin have a value equivalent to the administratively set deficiency charge, while capacity above these requirements has a value (effectively) of zero.

As discussed in section III.D.1 below, PJM retained Professor Benjamin F. Hobbs of Johns Hopkins University to evaluate alternative resource requirement (or demand) curves in connection with RPM. As part of that analysis, Professor Hobbs conducted extensive dynamic modeling simulations of a reliability adequacy construct with a single-deficiency charge pricing structure, similar to PJM's current approach. Professor Hobbs found that such a capacity pricing structure is subject to pronounced cyclical variations, in which reserves periodically fall below the required IRM due to underpayment for capacity, and then rise above the IRM as energy prices rise due to relative scarcity and new capacity moves in to take advantage of the higher returns. Under a single-deficiency charge capacity mechanism, high levels of new generation entry during booms seriously depresses prices, profits, and investment, which then tends to completely dry up investment in new capacity during busts, causing reserves periodically to fall below required margins. Professor Hobbs found that capacity approaches similar to PJM's current construct led to this type of price and investment swings under a wide range of conditions. As would be expected, Professor Hobbs found that this climate dampens efficient investment overall, as it heightens uncertainty, which in turn induces investors to demand higher profits.

The Commission has recognized as much, acknowledging that "dependence on price volatility for investment is an inadequate foundation for cost-effective financing of new infrastructure."[67]

As shown above, the PJM daily capacity market has exhibited this type of volatility, fluctuating between price extremes, depending on whether there is too little or too much capacity relative to the required reserve margin. As Mr. Bowring, the PJM Market Monitor, has concluded, "net revenue (in the PJM Region) has been below the level required to cover the full costs of new generation investment for several years and below that level on average for new peaking units for the entire market period."[68] Thus, as he observed, some units in PJM needed for reliability "have revenues that are not adequate to cover annual going forward costs," id., prompting their owners to seek retirement. The relatively low revenues, resulting from low capacity prices, have caused cancellations of proposed new generation. As discussed above, with loads increasing and generation not keeping pace, the result has been that reliability criteria violations have arisen in parts of the PJM region.

d. PJM has Experienced a Significant Decline in Recent Years in the Load-Following and 30-Minute-Start Capabilities of its Capacity Resources.

As Mr. Ott explains, PJM's current capacity construct treats all installed generation capacity the same, even though some units have added capabilities that bring

---

67 PJM Interconnection, 107 FERC at P 20.

68 Bowring Affidavit at 15.

added value to preserving system reliability.[69] To ensure reliable service, the PJM region must have available an adequate amount of resources that can respond to rapid increases in load, known as "load-following" resources; and resources that can start and stop several times a day on relatively short notice, known as "thirty-minute-start" resources.

While PJM presently is capable of meeting load-following criteria on a reliable basis, PJM has experienced a significant decline in recent years in load-following and thirty-minute-start capabilities. As Mr. Ott details, over the past four years, the amount of load-following generation offered in PJM has declined by nearly one-quarter, from approximately 44 percent of all generation megawatts offered in PJM in 2000, to only 34 percent of total generation offered in 2004. Mr. Ott also shows a decline of about one-third in the number of available starts-per-day (i.e., the number of times the unit can be turned on, turned off, and turned back on during the day to help the system track rapid increases in load) offered by combustion-turbine units. These offered available starts decreased from an average of 4.6 starts per day in June 2000 to 3.1 starts per day in August 2004.

Moreover, as Mr. Ott also details, most of the units retired in PJM recently had load-following capability, and that capacity is not being replaced by new load-following units. Ott affidavit at 32.

Mr. Ott observes that a significant reason for the decline in economically dispatchable generation stems from the high costs of maintaining older fossil-fueled steam units in a condition that allows them to ramp more quickly and cycle more frequently. Frequent cycling of such units accelerates wear and tear and increases maintenance costs. Owners of such units need an increased economic incentive in order to counter these increased maintenance costs and preserve the economically dispatchable range and cycling capabilities of these units. PJM's current capacity payment mechanism does not separately value these costs, nor are they separately compensated in the energy or ancillary service markets.[70]

---

[69] Ott Affidavit at 30-32.

[70] Indeed, as Mr. Ott also explains, these additional capabilities do not lend themselves to valuation in the energy or ancillary services markets. They are better suited to compensation through a capacity market.

e. Poor Long-Term Signals: Current Daily/Seasonal Capacity Credit Market not Well-Suited to Providing Long-Term Capacity Price Signals to Developers of New Generation.

PJM's experience with the current short-term capacity market indicates that market has design flaws. As Mr. Ott explains, the short-term market has not demonstrated the capability to sustain generation investment. Id. at 14-16. That market does not adequately quantify reliability requirements, nor does it provide a reasonable opportunity for planned resources to compete with existing resources. Although a capacity market exists only to serve reliability requirements, a short-term market is poorly suited to meeting those requirements.

The current capacity construct allows LSEs to commit generation resources to provide installed capacity to serve their network load capacity obligation on a day-by-day basis. Under the current rule, generation resources committed to the system as capacity resources can "de-list" from capacity resource status with as little as 36 hours notice. As discussed by Mr. Bowring in his affidavit, the current construct has not provided sufficient revenue to generators, thus sending a signal to those generators that they are not valued for reliability. The fundamental inconsistency between quantified reliability needs and the observed generation revenue adequacy results indicates that the current capacity construct does not properly quantify the reliability needs of the system.

Moreover, as discussed by Mr. Herling, the recent retirements also highlight an inconsistency between the capacity market and the long-term planning of the transmission system. The load deliverability analysis performed in the RTEP process requires, as input, the generation resources that will be available to support delivery of imported energy to load. Uncertainty in the generation resource availability for future years creates a significant amount of uncertainty in the future regional transmission plan. Since reliability is a fundamental requirement, this planning uncertainty cannot be sustained.

Some have suggested that forward uncertainty in generator availability should be addressed in the RTEP process by assuming "at-risk" generators will retire. This would not be an optimal solution. While PJM may be able to predict some generation retirements based on certain factors, it would be very difficult to predict accurately all generation retirements that might affect local deliverability. Conversely, if PJM used very conservative assumptions in an attempt to rule out adverse surprises, the resulting enhancements to the transmission system would not yield a least-cost solution, because neither PJM nor market participants would have sufficient information on other alternatives such as new generation or demand resources. The RPM auctions provide a superior mechanism to address forward uncertainty in generation availability because they provide transparent forward prices and other information to allow market participants to compete to resolve reliability concerns. To correct this problem, the PJM region needs to return to a longer-term forward capacity obligation to commit generation for future years.

f. Limitation of Capacity Resource Qualification to Only Existing Generation Resources.

Under PJM's current capacity adequacy construct, only iron in the ground can qualify as a capacity resource. There is no mechanism for planned generation units to compete to be capacity resources. Demand response solutions can only participate as credits against capacity obligations (known as ALM), but cannot compete head to head with generation for capacity resource status. Moreover, although it is well recognized that generation and transmission can provide alternative solutions to reliability needs, there currently is no forum for generation solutions and transmission solutions to compete directly against one another.

3. PJM, Stakeholders, and FERC have Recognized Such Shortcomings and have Tried for Years to Develop a New Capacity Construct for PJM

The limitations of PJM's current capacity construct have been recognized for some time, and PJM has been working with stakeholders (including neighboring system operators) on potential capacity market reforms for the past five years. Numerous task forces, working groups, and committees—JCAG, FAWG, RAM, etc.—have attempted to grapple with the problems. But no consensus resolution to the basic underlying problems has come out of these stakeholder processes.

The Commission has recognized and encouraged the efforts of PJM, its stakeholders, and neighboring systems to address shortcomings in their capacity adequacy rules.[71]

Following years of inconclusive effort, stakeholders invited PJM last summer to attempt to devise a comprehensive solution. In response, PJM developed an initial version of RPM. Over many subsequent months, the proposal was refined, in response to stakeholder feedback and additional evaluation and research. Despite great effort and cooperation from many stakeholders, it became apparent that positions on RPM were hardening, with a majority (predominantly load interests) opposed due to perceived price increases that would result in the short-term, and a large minority (predominantly generation interests) in favor.

On January 26, 2005, a fully developed RPM proposal came before the PJM Members Committee but did not receive a majority sector vote. PJM then scheduled a two day RPM stakeholder conference on February 17 and 18 to solicit oral and written feedback on the RPM proposal. The two day conference gave stakeholders an opportunity to suggest consensus revisions to the RPM proposal. The stakeholder process resulted in several stakeholder driven revisions to the RPM proposal. The revised RPM proposal came before the PJM Members Committee on March 17, 2005, but again failed to receive a majority sector vote. A significant majority of PJM stakeholders have indicated that they believe capacity market reform is necessary. However, they cannot agree on an alternative with super-majority support. While RPM has not received super-majority support, the other proposals that have been discussed (such as the EITCC and PPL proposals described above) do not have widespread support either.

Absent stakeholder consensus supporting a successor to PJM's current flawed capacity construct, the PJM Board of Managers has an independent obligation to ensure the safe and reliable operation of the PJM Region, and the creation and operation of a robust, competitive, and non-discriminatory electric power market in the PJM Region.

---

71 See, e.g., PJM Interconnection, 110 FERC at P 76; N.Y. Indep. Sys. Operator, Inc., 109 FERC ¶ 61,023, at P 6 (2004); FERC Staff Paper on Regional Choices for Implementing the Elements of the White Paper, at pp. 23-25 (July 7, 2003); Morgan Stanley Capital Group, Inc. v. PJM Interconnection, L.L.C., 96 FERC ¶ 61,331, at 62,269 (2001); PJM Interconnection, 95 FERC at 62,175, 62,179.

Acting pursuant to this responsibility, the PJM Board determined that the RPM proposal is in the best interests of the region, and that PJM should file the RPM proposal with the Commission.

V. RPM IS JUST AND REASONABLE. IT RETAINS AND BUILDS ON MUCH OF THE EXISTING CAPACITY CONSTRUCT, WHILE ADDRESSING AND RESOLVING CURRENT DEFICIENCIES IN AN INTEGRATED AND COMPREHENSIVE MANNER

A. RPM Retains Much of PJM's Existing Reliability Adequacy Construct

Although it makes many important changes, RPM retains much of PJM's existing reliability adequacy construct. In particular, RPM retains and builds on the following basic elements of the current approach, as described in section IV.C.1 above:

- The fundamental reliability standard remains the 1 day in 10 years LOLE criterion;
- There is no change in the process for setting the regional reserve requirement;
- The percentage reserve requirement remains applicable to the entire region;
- There is no change in the process of evaluating load deliverability and the reliability of subregions;
- As of today, each LSE is responsible for satisfying its allotted share of the regional reliability requirement;
- As of today, LSEs only pays a charge to support reliability to the extent they do not secure (through ownership or contract) their own resources;
- As of today, the key input into the reliability charge is the cost of new entry by a combustion turbine unit;
- Capacity obligations and resource values will continue to be stated on an unforced basis;
- There is no change in the standards or process for determining each LSEs load responsibility;
- LSE capacity obligations will continue to track load-switching on a daily basis, in the same manner as today;
- Demand side response retains the option to participate through Interruptible Load for Reliability credits, which are equivalent to the current ALM credits.

B. *Overview of RPM*

Under RPM, PJM will administer a series of auctions for each Delivery Year,[72] to match the region's need for capacity with offers to sell capacity, to determine the clearing prices to be paid to capacity resource sellers, and to determine the reliability charges to be paid by load serving entities.[73] If a seller's offer price is at or below the clearing price determined in the auction, then its offer clears and is accepted. Its resource then is committed to meet capacity requirements for the Delivery Year. The payments and charges determined through the auctions will be settled during the Delivery Year. The auction schedule, in relation to the Delivery Year, is shown in Figure 3.

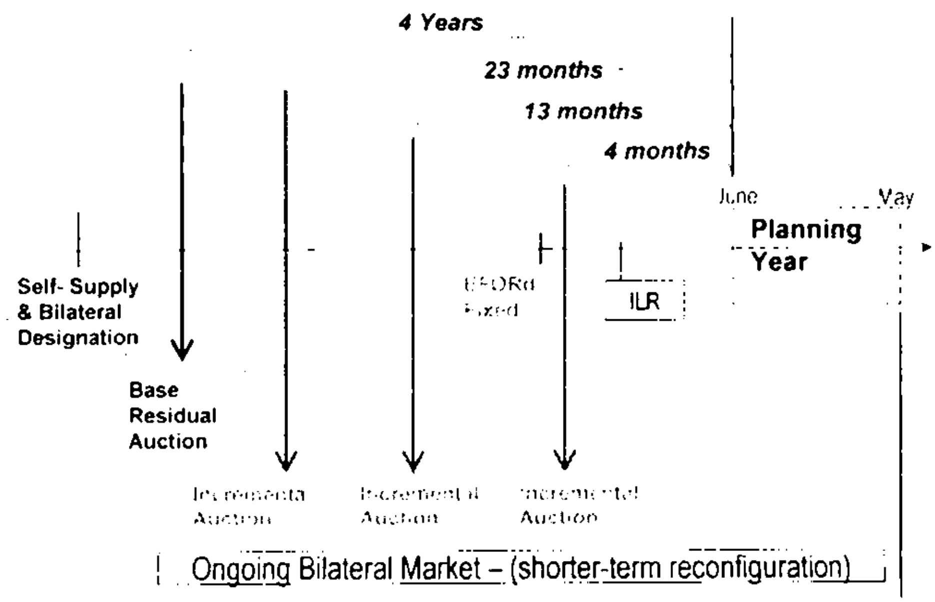


Figure 3 -- RPM Auction Timing

---

72 As with the Planning Period used in the RAA today, a Delivery Year is the 12-month period from June 1 of a calendar year to May 31 of the following calendar year.

73 As explained by Mr. Ott (at page 33 of his affidavit), PJM's costs to implement and administer RPM will be comparatively modest, i.e., up-front project implementation cost of $1.6 million, and no greater ongoing operational costs than PJM incurs today to adminster the current capacity construct..

Four years before each Delivery Year, PJM will conduct a Base Residual Auction to enable commitment of capacity resources needed to satisfy capacity needs, taking into account any owned or contracted resources identified by LSEs.[74] The market clearing method used in the auction will consider locational transmission constraints, as well as the PJM Region's need for certain "operational reliability" requirements, i.e., a minimum amount of capacity capable of adjusting output to follow changes in load, and a minimum amount capable of starting in 30 minutes or less.

The auction-clearing model uses marginal pricing to set prices based on these locational and operational reliability constraints, the submitted supply offers, and a VRR curve. As explained in Section III.D.1 below, the VRR curve charts a relationship between price and unforced capacity to establish the level of capacity that will provide an acceptable level of reliability. Based on these inputs, the auction will set:

(1) The price paid to capacity resources that are committed to the region in the auction; and

(2) The corresponding amounts to be paid by LSEs as a Locational Reliability Charge.

As a result of the locational constraints, the clearing price could vary among identified areas, known as LDAs, depending on whether transmission limits into such LDAs bind in the auction. The RTEP process currently identifies areas that have a limited ability to import capacity due to physical limitations of the transmission system, voltage limitations, or stability limitations, but that information is not reflected in capacity prices. Those areas identified in the planning process now will be used as LDAs in RPM.

Similarly, if either or both of the operational reliability constraints bind in the auction, resources supplying load following or 30-minute-start capabilities (as applicable) will receive additional compensation, based on the bids of such resources and the minimum required level of such resources needed for system reliability.

---

[74] To ensure all loads are covered, an LSE will offer its owned or contracted resources into the auctions, but with a "price-taker" bid. When it does so, its resources automatically will clear; it will receive RPM revenues during the Delivery Year as the seller of a capacity resource; and it will pay RPM reliability charges during the Delivery Year as an LSE.

RPM allows many more types of resources than today to qualify as capacity resources. Capacity resources will now include both existing and planned generation resources, as well as both existing and planned Demand Resources. Moreover, planned merchant transmission upgrades that provide incremental increases in import capability into constrained LDAs can be offered into the auction. This added feature will allow transmission upgrades to compete directly with local generation in constrained LDAs, ensuring that the auction does not consider local generation as the only solution to deliverability limitations that could be solved economically by transmission.

In addition to the Base Residual Auction, PJM will hold Incremental Auctions for the Delivery Year to provide market participants the opportunity to adjust their capacity market positions. The First Incremental Auction, held twenty-three months before the Delivery Year, allows market participants an opportunity to replace resources they committed in the Base Residual Auction, where the resource will be unavailable for such reasons as cancellation, delay, derating, EFORd increase, or a decrease in the value of a Planned Demand Resource. The costs of the resources committed in the First Incremental Auction will be recovered from the parties that needed to secure replacement resources.

PJM will conduct a Second Incremental Auction thirteen months before the Delivery Year, but only if PJM determines that there is a region-wide capacity shortage for that Delivery Year of more than 100 megawatts, as a result of a higher load forecast.[75] When these conditions are met, the auction will be held to commit the needed additional capacity. The costs of the additional resources committed in the Second Incremental Auction are recovered from all LSEs in the PJM Region.

PJM will conduct a Third Incremental Auction four months before the Delivery Year. As with the First Incremental Auction, this auction allows market participants an opportunity to replace resources committed in the prior auctions, that since have been determined to be unavailable, or reduced in value due to a revised calculation of EFORd.

---

[75] PJM prepares a preliminary load forecast for the Delivery Year before the Base Residual Auction, and then updates that forecast 15 months before the Delivery Year, so that there is enough time to conduct a Second Incremental Auction if necessary.

As with the First Incremental Auction, the cost of resources committed in this auction will be recovered from the parties that need to secure replacement resources.

In addition to having the opportunity to compete with generation in the RPM auctions, Demand Resources can be nominated three months before a Delivery Year as Interruptible Load for Reliability ("ILR"). PJM will certify the nominated resources as ILR if they meet the criteria established for demand resources. Certified ILR receives the same type of payments as Demand Resources that are offered and cleared in the auctions.

To ensure that committed resources fulfill their commitments during the Delivery Year, RPM includes various compliance and deficiency charges. These are closely patterned on the similar charges assessed under the RAAs today, but adapted to address the additional types of resources that can be committed in RPM.

RPM also includes provisions designed to protect against potential market power, including market structure tests, and avoidable-cost determinations similar to those addressed in other PJM proceedings.

Because RPM, when fully implemented, will address Delivery Years four years in the future, it includes transition provisions to address the first three Delivery Years after implementation, and to phase in certain of its new features.

Finally, RPM includes a reliability backstop auction to ensure that sufficient capacity is procured if there are repeated failures to commit adequate resources through the auctions described above. This backstop is triggered only if significant shortages are observed in the auctions applicable to four consecutive Delivery Years.

C. *RPM Recognizes the Locational Value of Capacity*

RPM values capacity based on its location, and will provide incentives for both the retention and construction of capacity where it is most needed. The Commission repeatedly has endorsed locational capacity requirements, finding that "features such as locational requirements for installed capacity may prove an effective approach to create stable revenue streams."[76] The Commission has found that market design improvements "are the preferred choice for resolving material Reliability Compensation Issues." Id.

[76] PJM Interconnection, 107 FERC at P 20.

As the Commission has stated, "designing and implementing a well-functioning and equitable [locational capacity] market represents a significant step in resolving reliability compensation issues."[77] The Commission not only accepted ISO-NE's locational capacity proposal, it ordered ISO-NE to modify that proposal to establish an additional capacity zone in southwest Connecticut, in light of evidence of reliability concerns in that area.

As the Commission found, a locational capacity mechanism is just and reasonable because it: 1)provides price signals to encourage investment that results in generation additions and improved reliability; and (2)values capacity in a way that accounts for the transfer limits of the transmission system.[78] The Commission agreed with ISO-NE that having too few capacity zones increases the likelihood of cross-subsidies. Id. at P 1. The Commission found that a locational approach in ISO-NE "will not only substantially reduce the need for out-of-market RMR agreements, but will also provide an incentive to construct new transmission infrastructure and capacity resources where they are needed most, since the market will produce the highest prices in those areas." Id. at P 67. The Commission also has approved locational capacity pricing for the NYISO.[79]

As shown in section IV.C above, PJM's current tariff rules do not differentiate capacity prices by location, but there is a growing need to introduce locational factors into the reliability adequacy program for the PJM Region.

RPM supplies a framework for a more reliable and cost-effective solution to these issues. Similar to the current capacity deficiency rate, the new RAA will require all LSEs to pay a reliability charge to the extent they do not prove they have secured sufficient capacity to cover their loads, but that charge, known as the Locational Reliability Charge, could vary by location. For each area, the charge equals the LSE's Daily Unforced Capacity Obligation in that area, times the Final Zonal Capacity Price in that area. An LSE will receive payments offsetting the charge to the extent it offers and clears Capacity

77 Devon I, 107 FERC at P37.

78 Devon II, 109 FERC at P24.

79 See N.Y. Indep. Sys. Operator, Inc., 105 FERC ¶ 61,108 (2003).

Resources in the RPM auctions, including by self-supplying owned or contracted resources.

The capacity areas used in RPM are known as LDAs. LDAs are determined using the same load deliverability analyses performed by PJM in the RTEP process, i.e., the comparison of Transfer Objective and Transfer Limit using an LOLE of 1 day in 25 years. Based on these analyses, the LDAs will be those areas that have a limited ability to import capacity due to physical limitations of the transmission system, voltage limitations, or stability limitations. This approach, i.e., "valu[ing] capacity in a way that accounts for the transfer limits of the transmission system," is just and reasonable, as the Commission found in Devon II.

For the first year under RPM, i.e., June 1, 2006 through May 31, 2007, the LDAs will be:

(1) The MAAC Region and Allegheny Power System ("APS") zone; and

(2) The Commonwealth Edison Company ("ComEd"), AEP, Dayton Power and Light Company ("Dayton"), Virginia Electric Power Company ("Dominion"), and Duquesne Light Company ("Duquesne") zones. These zones are shown on Attachment 3 to Mr. Herling's affidavit.

In the second year, 2007-2008, two more LDAs will be added. The two additional zones will be

(1) Eastern MAAC;[80] and

(2) Southwestern MAAC.[81]

In the third (2008-2009) and fourth (2009-2010) years, PJM will implement a full complement of LDAs, based on the areas analyzed in the RTEP process. While this list is lengthy, it does not mean that all of these LDAs necessarily will experience price

---

80 This LDA will consist of the zones of Public Service Electric & Gas Company ("PSE&G"), Jersey Central Power & Light ("JCP&L"), Philadelphia Electric Company ("PECO"), Atlantic City Electric Company ("AE"), Delmarva Power & Light Company ("DPL") and Rockland Electric Company ("RECO"). Although this LDA overlaps with the MAAC and APS zone described above, there is no requirement that such areas be mutually exclusive.

81 This LDA will consist of the zones of Potomac Electric & Power Company ("PEPCo") and Baltimore Gas & Electric Company ("BG&E").

separation. Rather, just as PJM tests each of these regions, zones, and sub-zones today to ensure compliance with reliability criteria, the capacity market now will have the opportunity to assess the adequacy of capacity prices in these areas. For these two years, the LDAs will be:

(1) MAAC region;
(2) ComED, AEP, Dominion, Dayton, and Duquesne;
(3) Virginia Power;
(4) eastern MAAC region;
(5) southwestern MAAC region;
(6) The western MAAC region consisting of the Pennsylvania Electric Company ("Penelec") zone;
(8) ComEd;
(9) AEP;
(10) Dayton;
(11) Duquesne;
(12) APS;
(13) AE;
(14) BGE;
(15) Delmarva;
(16) PECO;
(17) PEPCO;
(18) PSEG;
(19) JCPL;
(20) Metropolitan Edison Company;
(21) PPL;
(22) PSEG northern region; and
(23) Delmarva southern region.

PJM will determine and post the LDAs applicable to subsequent years (beyond the fourth year) at least four months before the start of the first RPM auction for each such year. While changes are not currently expected from the list shown for the third and fourth years, this flexibility will ensure that for any given year, the LDAs will match the areas assessed in the RTEP process.

Under RPM, there will be separate VRR curves determined for each LDA, reflecting differences in loads, internal capacity requirements, and the cost of new entry[82]

---

82 The cost of new entry varies slightly in different parts of the PJM Region, reflecting slight geographic differences in labor and other expenses. If an LDA covers more than one area for which PJM determined the cost of new entry, PJM will use the lower CONE value in that LDA.

for those LDAs. Capacity resources eligible to be offered into the RPM auctions will be identified by LDA. In the RPM auctions, the optimization algorithm will take into account, among other factors, the resources available in each LDA, the price offers from such internal resources, the constraints on delivering energy into such LDAs (i.e., the Transfer Limits), and the price offers from resources external to each LDA.

If an LDA is constrained, i.e., it has reached the limits of its ability to import less expensive capacity from outside the LDA, then the capacity price in that LDA will separate from the capacity prices in the rest of the PJM region, similar to the LMP price separation that occurs today in the day ahead and real time energy markets when congestion arises. In RPM, the locational premium above the base regional cost of capacity is referred to as a Locational Price Adder. The Locational Price Adder reflects the added value of capacity resources located inside the constrained LDA, and is available to existing or planned generation capacity resources, and existing or planned demand resources, so long as they are located in the LDA.

As explained in more detail below, the Locational Price Adder also is available to planned transmission upgrades that clear in an RPM auction, if the upgrade increases the Transfer Limit of the LDA. By creating direct opportunities for transmission upgrades to resolve the local import concerns more efficiently than local generation, RPM thus allows even more competition than the locational capacity markets previously approved by the Commission, and further reduces the likelihood of future reliance on out-of-market compensation.

When an LDA is constrained, resulting in a Locational Price Adder, RPM mitigates the impact of that higher price on loads, by giving each LSE credit for a share of the import capability into the zone. In a constrained, price-separated LDA, that import capability represents the ability to access lower-cost generation from outside the LDA. To apportion the value of that capability fairly among all loads in the LDA, RPM grants each LSE in a constrained LDA a Capacity Transfer Right ("CTR"). The CTR entitles the LSE to a payment equal to the Locational Price Adder, times the LSE's pro rata share (based on load ratio share) of the capacity imported into the LDA. Similar to the Financial Transmission Rights used by loads to hedge transmission congestion, CTRs entitle the LSE to payments that offset, in part, the higher capacity price it pays to ensure reliable service to its loads in an import-limited LDA.[83]

RPM thus provides an integrated, competitive market solution to existing or potential load deliverability constraints for a Delivery Year. Because it arises from the competing sell offers of multiple market participants (which offers in turn were influenced by the market knowledge and expectations of each individual seller), the Locational Price Adder also can provide a valuable forward price signal. Such a signal will assist market participants that enter bilateral capacity contracts for the future. PJM will aid this process by supplying market participants with extensive information before each auction, including PJM's planning analyses of future loads, system resources, and capabilities. For this purpose, PJM anticipates providing more information than the information in the RTEP five-year plan (which tests for actual load deliverability criteria violations), identifying areas that may be trending toward such violations beyond five years. While PJM generally does not rely on such longer-term projections for purposes of mandating transmission enhancements in the RTEP, there is no reason not to supply capacity market participants with this information so they can factor the information and uncertainty into their decisions.

D. *RPM's VRR Curve is More Likely to Produce Better Reliability, at Lower Cost, Than PJM's Current Approach*

The Commission already has determined that use of a demand curve, in principle, is a just and reasonable improvement over capacity adequacy mechanisms that, like PJM's current approach, use a single deficiency rate to cap the cost of capacity resources.[84] The rigorous independent analysis PJM commissioned to assess its VRR curve options, provides compelling support for the same conclusion in this case.

---

83 As discussed below, customers that bear the cost of transmission upgrades that increase import capability into an LDA receive Incremental CTRs based on that increase in capability.

84 Devon II, 109 FERC at PP 42-44; Devon III, 110 FERC at P 17; N.Y. Indep. Sys. Operator, Inc., 105 FERC at P 20.

1. *Professor Hobbs' Dynamic Analysis Shows that PJM's Selected VRR Curve is very Likely to Yield Greater Reliability and less Volatility at Lower Cost than the Current, "Vertical Demand Curve" Approach*

Given the Commission's precedent approving the use of downward sloping demand curves for capacity pricing, PJM examined a variety of potential VRR curves to determine which would best produce price signals that encourage new generation construction at a reasonable capacity cost to electricity end-users. To this end, PJM asked Professor Benjamin F. Hobbs of Johns Hopkins University, a scholar well-noted for his expertise in sophisticated modeling of electricity markets "recognizing transmission and other technical constraints and imperfectly competitive behavior by market participants," to evaluate alternative VRR curves for RPM.[85]

Professor Hobbs develops and uses "a dynamic model that simulates generator investment over time in response to incentives in the energy, ancillary services, and capacity markets."[86] The model calculates three sets of indices –"forecast reserve margin, generator revenue and profits, and consumer payments for capacity and scarcity rents" to judge how well different VRR curves perform with respect to reliability and cost. Id. Professor Hobbs then tests these results by varying the model's assumptions "concerning the risk attitudes and behavior of builders of new generation" to ensure that the conclusions are sound. Id. at 5. Professor Hobbs concludes that "the advantages of the downward sloping demand curve . . . relative to the vertical demand curve [implicit in

---

85 Professor Hobbs' previous consulting engagements include assignments on behalf of the Commission's Office of Economic Policy.

86 Hobbs at 6. Professor Hobbs describes and supports in detail the assumptions used in his dynamic model of the capacity markets. As he explains, his objective was to develop "[a] simple, transparent model that captures the basic features of the capacity market," because such a model "is most likely to lead to useful insights and conclusions about the relative performance of different demand curves." Hobbs at 16. The "basic features" of the capacity market integrated into his dynamic model include "uncertain loads, the dependency of forecast profits on past profits, generator risk aversion, increased investment in response to increased profits, and the effect of reserves upon energy and ancillary service market revenues and system reliability." Id.

PJM's current capacity pricing rules] prevail for wide variations in these [investor attitude] and other model assumptions." Id. at 7.

Professor Hobbs performed his dynamic simulation tests on five different VRR curves, as displayed on Figure 4, and described below:[87]

1. A vertical demand curve, which yields an annual payment to generators equal to twice the annual fixed costs of a CT, minus the average annual energy and ancillary services revenue offset ("2 X CONE - E/AS"), for any forecast reserve level at or below the target IRM, and zero payment for any reserve levels above that target margin;

2. A demand curve based on the expected value of lost load when average reserve margins diverge from the target IRM;

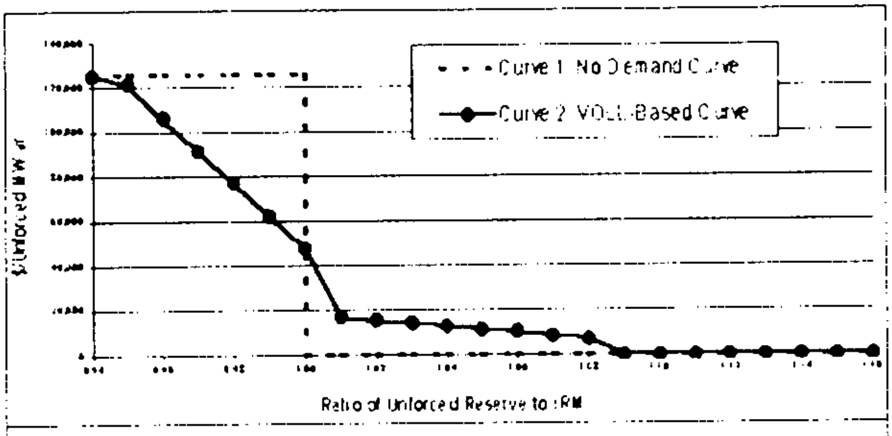
3. A downward sloping demand curve with four segments: (a) a horizontal segment with an ICAP price equal to two times the fixed cost of a turbine if the reserves are less than 96% of the target reserves, minus the average E/AS gross margin, divided by one minus the forced outage rate; (b) another horizontal segment with a zero price if the installed capacity exceeds the target installed reserve margin of 15% by 5% or more; and (c) two linear downward sloping segments located between the other two, with the right-hand one having a shallower slope. The slope of these two lines changes at a point where capacity equals the IRM, and price equals CONE minus the minus the average E/AS gross margin, divided by one minus the forced outage rate;

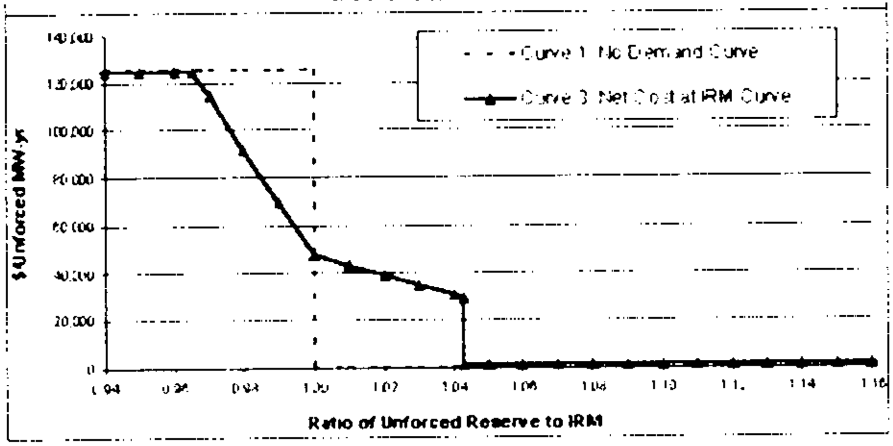
4. Another downward sloping demand curve, similar to the above, except shifted 1 % to the right; and

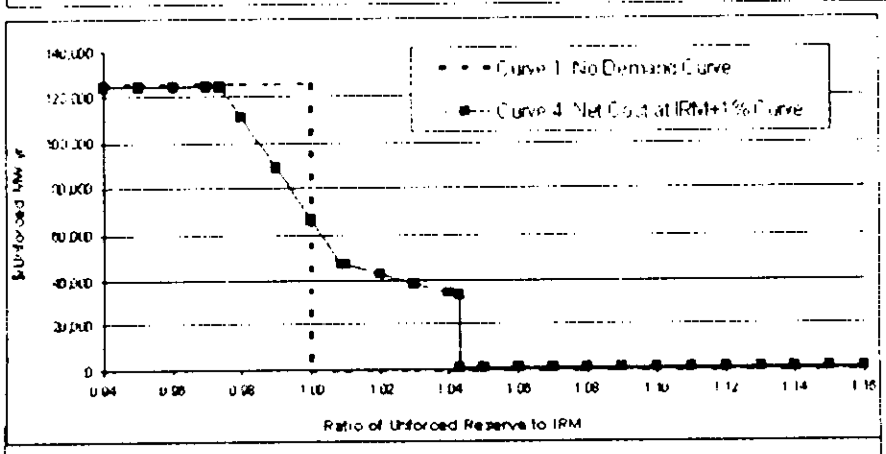
5. Another version of the downward sloping curve, except shifted 4 % to the right.

Figure 4 on the next page contrasts each of the curves 2 through 5 with the current "vertical" demand curve:

[87] In these curves, the "X" axis is expressed as a ratio of the unforced reserve margin to the target unforced reserve margin, so that a value of 1 signifies that the target is just met. Multiplying this ratio by (100% + the target reserve in percent) and then subtracting 100% converts this ratio into a reserve margin. For example, if the ratio is 1.043 where the sloped demand curve approach zero price, the reserve at this point is equal to 1.043 * (100% + 15%) - 100% or 20%.


Curve 1 No Demand Curve
Curve 2 VOLL-Based Curve
$/Unforced MW-yr
Ratio of Unforced Reserve to IRM


Curve 1 No Demand Curve
Curve 3 Net Cost at IRM Curve
$/Unforced MW-yr
Ratio of Unforced Reserve to IRM


Curve 1 No Demand Curve
Curve 4 Net Cost at IRM+1% Curve
$/Unforced MW-yr
Ratio of Unforced Reserve to IRM

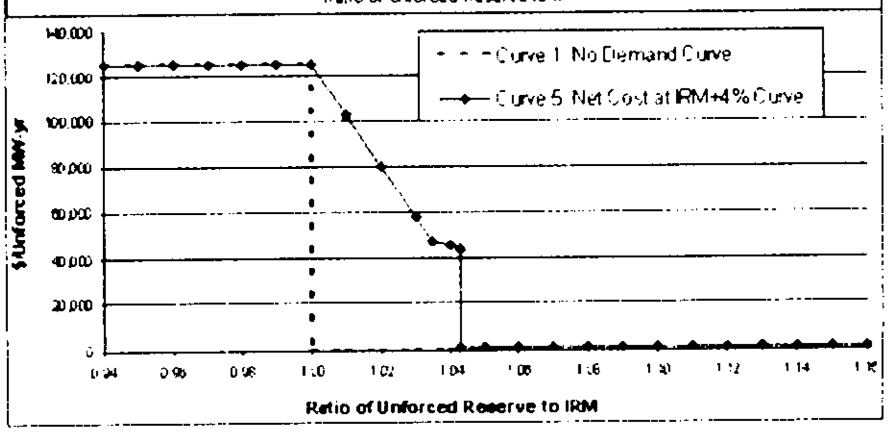

Curve 1 No Demand Curve
Curve 5 Net Cost at IRM+4% Curve
$/Unforced MW-yr
Ratio of Unforced Reserve to IRM

Figure 4. Five Alternative Demand Curves: ICAP Price Paid to Unforced Capacity as Function of Reserve Margin (Expressed as Ratio to Target Unforced Capacity)

In analyzing the impact of these curves to determine the level of revenues they would produce for generators, Professor Hobbs assumed that total generator revenues would equal the income from the capacity payment for a given curve, plus revenues for energy and ancillary services (set at $28,000/MW-yr for the base case, and $21,000 in his sensitivity cases). The lower value assumes that the benchmark CT used for these calculations will operate only during peak hours.

The results of the analysis of these five curves are shown in Table 3 below, reprinted from Professor Hobbs' affidavit:

Table 3.

Summary of Results of Dynamic Analyses of Five Alternative Demand Curves

Curve	Forecast Reserve Indices: % Years Forecast Reserve Meets or Exceeds IRM	Forecast Reserve Indices: Average % Forecast Reserve over IRM (Standard Deviation)	Generation Profit, $/kW/yr (standard deviation [s.d.]) IRR	Components of Generation Revenue: Scarcity Revenue $/kW/yr (s.d.)	Components of Generation Revenue: E/AS Fixed Revenue $/kW/yr	Components of Generation Revenue: ICAP Payment $/kW/yr (s.d.)	Consumer Payments for Scarcity + ICAP $/Peak kW/yr (s.d.)
1. No Demand Curve	39	-0.44 (1.92)	66/35.3% (113)	47 (85)	10	70 (57)	129 (121)
2. Original PJM Curve, Based on VOLL	54	-0.06 (0.74)	25/21.2% (73)	37 (70)	10	39 (14)	84 (78)
3. Alternative Curve with New Entry Net Cost at IRM	92	1.23 (0.87)	15/17.5% (53)	26 (52)	10	40 (4)	74 (55)
4. Alternate Curve with New Entry Net Cost at IRM+1%	98	1.79 (0.90)	12/16.6% (46)	21 (44)	10	42 (7)	71 (48)
5. Alternate Curve with New Entry Net Cost at IRM+4%	98	3.40 (1.05)	13/17.0% (41)	14 (31)	10	50 (20)	74 (43)

All of the downward sloping VRR curves perform better than the vertical curve (Curve 1, analogous to PJM's current capacity pricing). For Curve 1, the average percentage reserve margin is less than the IRM, and has a large standard deviation, reflecting substantial fluctuations above and below the reserve margin. Similarly, the average profits demanded by generators are higher than for any other case, and again have a large standard deviation, indicating substantial swings and volatility. Continuing the trend, the average payments by consumers (for both scarcity payments in the energy market and capacity payments) are highest for the vertical demand curve case, again with a very large standard deviation.

PJM considered a requirement curve based on the value of lost load as an alternative to relying on the cost of new entry. Rather than valuing incremental capacity at replacement cost (i.e., the cost of new entry), this curve values capacity based on the cost to the customer of having its service interrupted. As can be seen from the results for Curve 2, this approach performed poorly, providing inadequate assurance of reliability, and relatively high cost.

Comparing the three downward sloping curves, the curve that pairs the net CONE with IRM (Curve 3) performs reasonably well, but not as well as the other two. That curve achieves the target IRM in fewer of the years, and results in slightly higher costs to consumers. The curve that pairs net CONE with IRM + 1% (Curve 4) exhibits better reliability, with reserves at or exceeding IRM in 98% of the years. Capacity payments by consumers are only very slightly above the capacity payments for the IRM + 0% curve, and total consumer payments (including both capacity and scarcity payments in the energy market) are less. Profits demanded by generators are comparatively low, as are the standard deviations for all three metrics, indicating less volatility.

The last downward-sloping curve, which pairs net CONE with IRM + 4% (Curve 5), exhibits the same level of reliability as Curve 4. However, consumer payments for capacity are higher than for Curve 4, with a greater standard deviation. Although scarcity costs are the lowest of any curve, these do not offset the higher capacity costs, so total costs to consumers is higher than for Curve 4.

To test the durability of the comparative performance of the five curves, Professor Hobbs next subjected those curves to numerous sensitivity analyses. He tested variations in two of the demand-curve-shape parameters:

(1) Lowering the highest ICAP price below 2 X CONE – E/AS; and

(2) Forcing the curve to intercept zero price at either IRM + 14 % or IRM + 10%.

He also tested variations in four behavioral assumptions (varying the parameters several different ways in each instance):

(1) The amount of capacity bid in and built when profits are high;

(2) The dollar level of bids submitted by existing and potential new capacity;

(3) Various degrees of risk aversion, from neutral to extreme; and

(4) The weight placed on recent profit history in forecasts of future profits.

In addition, Professor Hobbs tested the sensitivity of the results to differences in the assumed level of E/AS gross revenues (i.e., $ 21 kW/yr versus $ 28/kW/yr, as noted above); and variations in the slope of the demand curves and in growth rates for weather-normalized peak loads.

After conducting and evaluating these numerous sensitivity cases, Professor Hobbs finds that some of them improve the performance of the vertical demand curve in some respects, but that the sloped demand curves still perform best. As to the numerous variations in market participant behavioral assumptions, he finds that "under no assumptions" is the vertical curve preferable. Similarly, changes in weather-normalized peak growth rates "have significant impacts on the specific numerical performance of the five curves, but not on their general performance relative to each other.." Hobbs Affidavit at 65.

Overall, Professor Hobbs concludes that "the conclusion regarding the desirability of sloped curves (especially Curves 4 and 5) relative to Curve 1 (no demand curve) is robust with respect to these assumptions," but that "the precise financial consequences" depend on the assumptions made. Thus, while there is significant uncertainty regarding the effects of future capacity mechanisms on consumers, "the risks are lower if a sloped demand curve is used." Id.

In other words, as would be expected with an effort to project market behaviors decades into the future, there is a wide range of possible outcomes.[88] But across a wide range of reasonable assumptions, a sloped demand curve performs better—for consumers and for reliability—than the single-deficiency charge approach embedded in PJM's current filed agreements.

2. *PJM Selected the VRR Curve that Offers the Best Combination of Reliability and Cost*

As explained by Mr. Ott, PJM chose as the initial VRR curve for this RPM filing Professor Hobbs' Curve 4, as shown on Figure 5.[89] PJM judged that this curve offered the best combination of adequate generation reserves and reliability for reasonable cost, and Professor Hobbs' analysis provides ample support for that choice.

But as the filed tariff sheets make clear, and as Mr. Ott explains, PJM does not offer this as the final word. As indicated above, PJM expects a robust discussion and analysis of the VRR curve parameters in the context of the Commission's consideration of this filing. Ultimately, however, there is no substitute for experience. Accordingly, PJM has committed to a process to evaluate the VRR curve parameters at least every three years.[90] This commitment, coupled with the ample support provided for the initial VRR curve, provides assurance that the filed approach is just and reasonable.

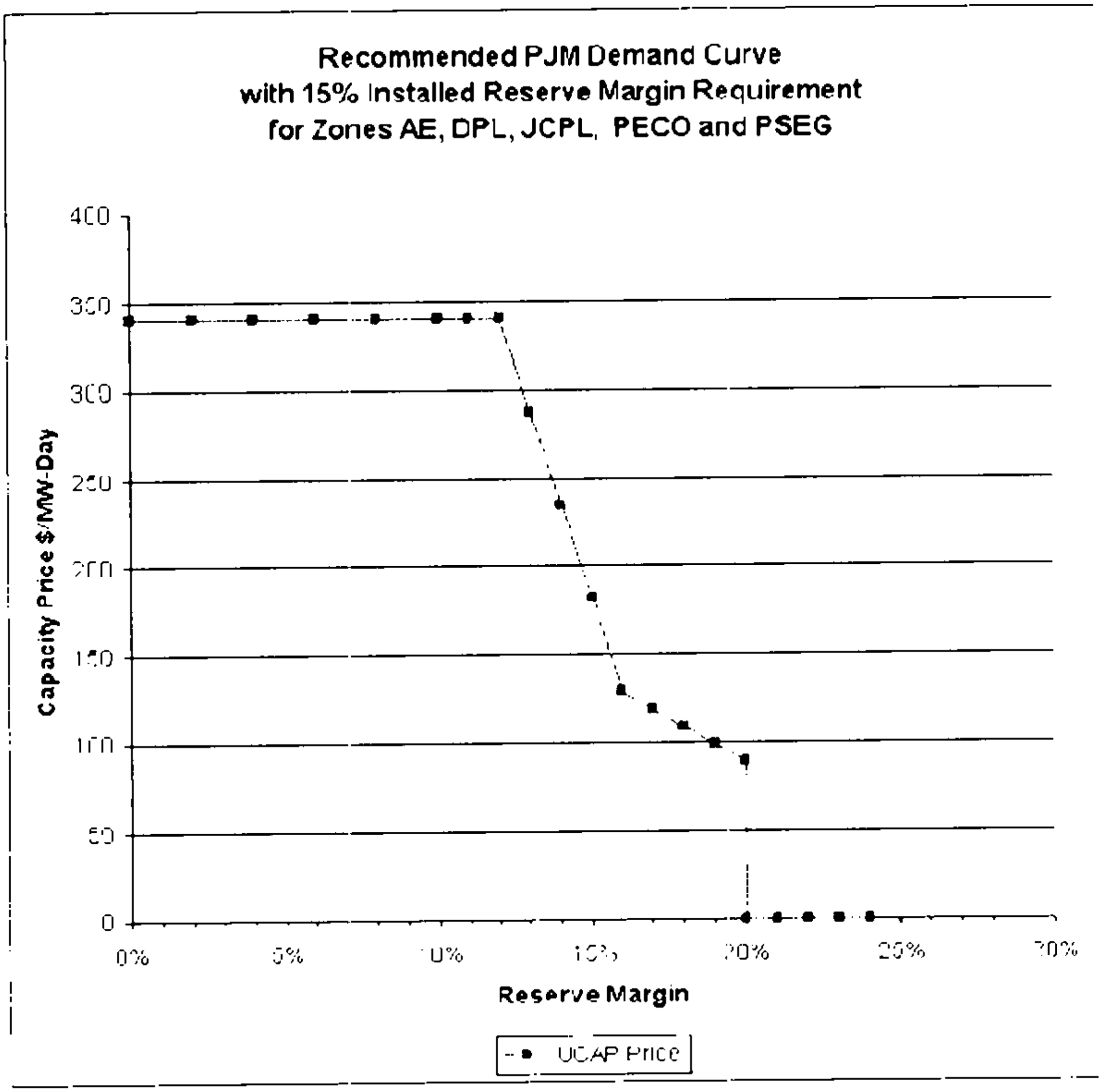
---

88 Cf Devon IV, 110 FERC at P 22(upholding ISO-NE's analysis in support of its LICAP zone proposal, where its "two sets of assumptions formed a broad range of likely outcomes," and similar results were observed "throughout that range.")

89 The VRR Curve shown on Figure 5 reflects the cost of new entry ("CONE") estimate for certain zones in the eastern PJM region. There are two other CONE estimates (reflecting slight geographic differences in equipment, labor, or other costs) that together cover the remaining zones in PJM. Because the CONE estimates vary by only a few thousand dollars, all three resulting curves have essentially the same shape, i.e., that shown on Figure 5.

90 See Attachment Y § 5.10(a)(ii).

Figure 5



3. *The Estimated Cost of New Entry Used in the VRR Curve is Just and Reasonable*

As is apparent from Professor Hobbs' analysis, the Cost of New Entry ("CONE") is a key parameter that defines the shape of the VRR curve. For purposes of RPM, the Cost of New Entry will be fixed in the Tariff, and subject to change only through a tariff filing, preceded by a stakeholder review process.[91] As with the other parameters and

[91] Id. § 5.10.

shape of the VRR curve. PJM commits to review the estimated Cost of New Entry with stakeholders at least every three years.

The CONE values added to the PJM Tariff by this filing vary slightly from area to area within PJM, reflecting geographic differences in labor and other costs. Those values are $198 per MW-day in the PSE&G, JCP&L, AE, PECO, DPL, and RECO zones; $203 per MW-day in the PPL, BGE, PEPCO, MetEd, Penelec, APS, Duquesne and UGI zones; and $202 per MW-day in the AEP, Dominion, Dayton, and ComEd zones.

PJM commissioned an independent study by Strategic Energy Services, Inc ("Strategic") to develop the CONE values used for this filing. As explained in the study, which is presented by Mr. Ray Pasteris with his affidavit, Strategic identified a type of generator representative of new entry in PJM, and determined its fixed revenue requirements. Revenue requirements are based on total project capital costs and annual fixed operations and maintenance expenses of a combustion turbine simple cycle peaker power plant addition. As noted above, Strategic prepared these estimates for three different areas in PJM.

Strategic considered two CT power plant design configurations: one based on the GE Frame 7FA unit and another based on the GE LM 6000 unit. Newly constructed CT plants, including several in the PJM Region, have incorporated these units, and the same two units were the focus of similar CONE studies prepared recently by consultants retained by the New York ISO and ISO-New England. Strategic relied on the Wood Group, a power plant design build firm with CT construction and O&M experience, to develop the plant capital cost estimates for both types of units. Strategic used debt terms, and an interest rate and debt-to-equity ratio, that are consistent with the financial structure of a creditworthy integrated electric utility or independent power producer, and a target return on equity of 12 percent. Tax depreciation and tax rates were consistent with federal and state law for the geographic areas studied. As explained by Mr. Bowring, the CONE estimate properly relies on a nominal levelized financial model, since the resulting value will be used to clear capacity markets potentially through the 2013 Delivery year.[92]

Strategic found that the GE Frame 7 required significantly lower fixed revenue than the LM 6000, and concluded that it was the lowest cost CT plant. Based on this

---

92 Bowring Affidavit at 11.

analysis, PJM accepted Strategic's recommendation to use the fixed costs of the Frame CT as the Cost of New Entry for all three areas of PJM.

Strategic also compared their results with similar studies performed recently for ISO-NE and the NYISO. The three studies analyzed similar types of generators, and used similar financial assumptions. However, Strategic's estimate was the lowest of the three, yielding a CONE value of about \$59 kw-yr, versus about \$87 kw-yr in the other studies.

4. *PJM's Formulaic Approach to Determining the Net Energy and Ancillary Service Revenue Offset is Reasonable and Appropriate for Purposes of RPM*

The VRR curve employs a net Cost of New Entry, offsetting the fixed capital and O&M costs of a combustion turbine generator with an estimate of the energy and ancillary service revenues the CT plant operator is likely to receive in PJM. That revenue offset will be determined using a methodology stated in the tariff, rather than a fixed amount. The offset will be determined as the annual average revenues that would have been received by a reference resource during the most recent six years, based on (1) the heat rate, variable cost, and other characteristics of the reference resource; and (2) the actual fuel prices and LMPs experienced in the PJM Region during that six-year period. Under this approach, net revenues are calculated based on how a unit with the characteristics of the CT for which the CONE is calculated would have operated under actual PJM prices. The revenues received by the Reference Resource include ancillary service revenues of \$2,254 per MW-year. The variable costs of the Reference Resource include \$5 per MW-hour for variable operations and maintenance costs. The reference resource is defined as a combustion turbine that is reasonably representative of new generating units that could be proposed for construction in the PJM Region, and for which reliable data is available.[93]

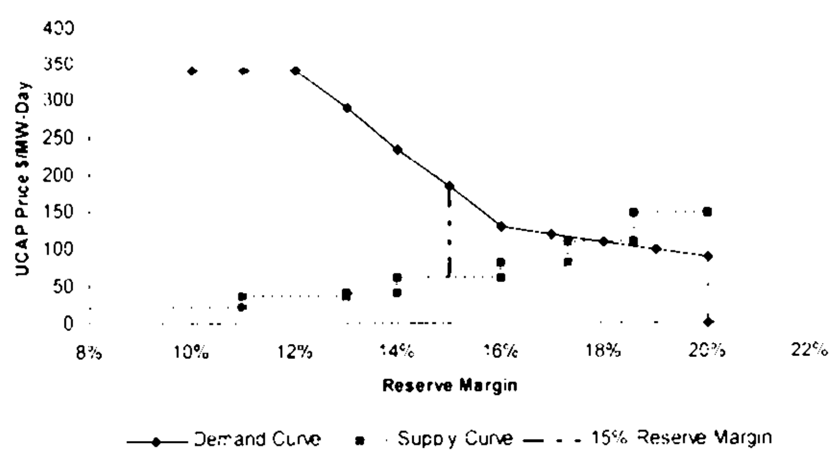
[93] Id. § 2.58.

5. *RPM Auctions Clearing Above the IRM Will Produce Lower Capacity Costs, and Likely Lower Energy Costs as Well*

The filed tariff sheets explicitly recognize that an RPM auction may clear at a capacity level higher than the installed reserve margin. However, as Mr. Ott explains, when this happens, the higher capacity commitment is obtained at lower cost.[94] To be clear, clearing more capacity with the chosen VRR Curve results not merely in a lower unit cost, but a lower total cost. For example, Figure 6 below, from Mr. Ott's affidavit, shows the chosen VRR curve and a sample supply curve formed from sell offers submitted in an RPM auction. The two curves intersect, and the auction clears, at a capacity level that yields an 18% reserve margin, with a clearing price of \$109 MW-Day. By clearing at this level, the system cost (assuming for ease of illustration a system peak of 1000 megawatts) is as follows:

System Cost = System Peak x (1 + Reserve Margin) x Clearing Price
= 1000 MWs x (1 + .18) x \$109/MW-Day
= \$128,620 Day

Figure 6 - RPM Optimization Clearing
Lowest Total Cost



---

[94] Ott Affidavit at 12.

By contrast, if the auction were forced to clear at the point on the VRR curve corresponding to the target IRM of 15%, where the price is \$182/MW-Day, then the system cost would be:

System Cost = System Peak *x* (1 + Reserve Margin) *x* Clearing Price
= 1000 MWs x (1 + .15) x \$182/MW-Day
= \$209,300/Day

In short, the VRR curve commits more capacity at a cost that is lower by one-third. The relationship illustrated here—i.e., more capacity at lower cost—holds for every point on the proposed VRR Curve, as shown on Table 1, which also appears on page 12 of this transmittal letter. This relationship also holds regardless of the load level, i.e., whether the curve is applied to clear the region as a whole or to clear only an individual LDA. As can be seen, the overall cost to procure capacity is highest in scarcity conditions, i.e., when the reserve margin achieved by the resources cleared in the auction falls short of the IRM target set by the PJM Board. The total capacity cost then goes down (not just on a unit basis, but on a total-cost basis) as more capacity is cleared.

Region-wide Capacity Obligation **147321**

Reserve Cleared by Auction	Capacity Cleared MW	Capacity Price from VRR $/MW-Day	Capacity Cost $ Million per Day	Reduction in Cost $ Mil/Day	Reduction in Cost $ Bil/yr
12%	143478	340	49	Reference	Reference
13%	144759	288	42	7	3
14%	146040	235	34	15	5
15%	147321	182	27	22	8
16%	148602	129	19	30	11
17%	149883	119	18	31	11
18%	151164	109	16	32	12
19%	152445	99	15	34	12
20%	153726	89	14	35	13

The table above shows only the capacity cost savings. Under RPM, the capacity cost savings shown above will be augmented by energy cost savings, which, as Mr. Ott shows, could be significant. As both Mr. Ott and Professor Hobbs explain in their affidavits, the commitment of capacity at a higher reserve level will tend to decrease energy market prices. To estimate this impact, Mr. Ott presents in his affidavit the results of an analysis of varying reserve margins on load payments and locational energy prices.[95] These energy production cost savings are in addition to the reduction in scarcity costs in the energy market described above with respect to Dr. Hobbs' analysis.

PJM used the General Electric Multi-Area Production Simulation ("GE-MAPS"), MW-Flow program, which can perform realistic simulations based, as is PJM's energy market, on security-constrained unit commitment and economic dispatch. PJM also used the detailed generation database maintained by GE, as well as a detailed electrical model of the entire transmission system. The GE MAPS MW Flow program is commonly used

[95] Ott Affidavit at 23-26.

to model generator production costs and locational prices.[96] The model takes into account operating characteristics of the individual generation units, constraints imposed by the transmission system, and operating and spinning reserve requirements. Accordingly, the analysis "provides a reasonable estimate of the impact [of] varying levels of installed generation reserve where security-constrained economic dispatch is used to meet entire market demand." Ott Affidavit at 15.

As Mr. Ott explains, PJM started with a base case of the GE MAPS 2003 Eastern Interconnection model and database, and updated the fuel costs to expected 2007 levels. To gauge the impact of varying reserve levels, the analysis progressively retired PJM capacity resources (by unit-installation date, from earliest to latest), until the desired reserve margin was achieved, i.e., 22%, 20%, 18%, 16% and lower levels, and then calculated the resulting generation capacity, payments by load, the weighted average energy rate, and generation production cost.

The analysis found substantial energy cost savings if capacity resources are committed at higher reserve levels. For example, the current PJM installed reserve margin is 15 percent. If the VRR curve operated to commit capacity resources at an 18 percent installed reserve margin, the analysis estimates that increased generation participation by these capacity resources in the energy market would cause energy payments by LSEs to decrease by $936 million per year, compared to load payments under the 15 percent scenario. These energy savings would be in addition to the savings in capacity costs by clearing excess reserve on the VRR curve as shown earlier.

E. *RPM's Four-Year-Forward Auction Promotes Competitive Infrastructure*

RPM is based on four-year-forward capacity commitments, thereby allowing planned generation, planned transmission upgrades and planned demand response, a meaningful opportunity to compete directly with existing resources. As Mr. Pasteris explains in his CONE study (at page 23 of that study), four years is the expected

---

[96] The GE-MAPS model was used in several recent studies, such as the SERUC study and the NERTO study to analyze the benefits of larger regional energy markets.

development schedule for a new combustion turbine. The four-year forward approach creates long-term forward transparent investment signals and significantly reduces market power concerns.

Notably, RPM represents a return to the type of long-term forward capacity commitments used in the PJM region from 1974 to 1999. Through RPM, PJM is taking to heart the Commission staff's advice that "[e]ach region should consider the time it takes to develop new supply and demand response infrastructure in the region and how this should affect the time frame for resource planning."[97] Moreover, in a recent analysis on capacity market reform commissioned by the NYISO, ISO-NE, and PJM, the retained experts concluded that "a minimum three-year planning horizon would be required to enable such a market to be a deciding factor in competing suppliers' decisions to construct new capacity."[98]

As Mr. Ott explains, "a market incorporating both pricing and lead-times that support new entry will help establish transparent investment signals and should significantly reduce market power concerns." Ott Affidavit at 15. The four-year-forward price signal, based on competitive generation, transmission, and demand resource sell offers, "should reflect the market's expectations about future conditions, including such factors as relative fuel costs and regulatory changes, such as environmental regulations," and this information "should be very valuable to investors considering alternative resource options." Id.

In addition, as a long-term price signal, "it should be relatively stable, especially compared to the volatile short-term pricing that characterizes the current PJM capacity market." Id. As Professor Hobbs explains in his affidavit, a generation investor has less information on future capacity prices under the current approach (with market periods extending only one year) than the investor would have under a four-year forward approach. This reduced uncertainty translates into reduced cost. Professor Hobbs quantifies this effect, showing with his dynamic economic analysis that generator

97 FERC Staff Paper on Regional Choices for Implementing the Elements of the White Paper, at 24 (July 7, 2003).

98 N.Y. Indep. Sys. Operator, Inc., 109 FERC at P 4, citing National Economic Research Associates, Cent. Res. Adequacy Mkts. for PJM, NYISO, and NE-ISO (Feb. 9, 2004).

required profits and consumer payments increase, while average reserve margins decrease, under a one-year ahead market compared to a four year ahead market.

Longer term price signals also should incent longer term bilateral contracts, as an effective means of hedging the reliability charges assessed under RPM. As Mr. Ott explains, "[t]his will help orient market participant objectives with the system's reliability needs, and help ensure the long-term viability of the competitive market model in the electric industry." Ott Affidavit at 15.

RPM's four-year-forward approach also should substantially eliminate short-notice announcements of generation retirements. Under RPM, not only will resources be committed four years in advance, but the onus will be on the party committing the resource to replace it should it become unavailable before the Delivery Year.

Although it establishes commitments four years in advance, RPM also contains important features to preserve market participant flexibility. The First and Third Incremental Auctions, conducted 23 months and 4 months before the Delivery Year, respectively, recognize that conditions may change after the initial commitment of capacity, and allow market participants to replace previously committed resources. The Third Incremental Auction also provides an opportunity to address any changes in a generator's unforced capacity values resulting from final updates of force outage rates for the year at issue.

RPM also includes provisions to resolve any concerns about the accuracy of long-term load forecasts. The Second Incremental Auction, conducted thirteen months before the Delivery Year, provides a means to secure additional capacity if the final load forecast for the PJM Region is 100 megawatts or more higher than the initial load forecast.

Accordingly, RPM's four-year-forward commitment approach creates much needed synergy between transmission planning, competitive generation investment, demand-response infrastructure investment, and generation retirement planning. RPM provides a more consistent forward planning model that supports infrastructure investment and sustains long-term system reliability.

Finally, while PJM believes that the four-year-forward approach provides the best combination of available information and forward signals, PJM recognizes that the choice of the forward period represents a balance among many factors, including the risk of estimation error (which increases as the horizon recedes), and the ease of participation by resources with relatively long lead times (which increases as the horizon advances). PJM believes that what is crucial is a market that is sufficiently forward to provide the opportunity for additional competition and a greater degree of forward price certainty, while not being so long that the estimation errors create a substantial risk of too much construction should the expected load fails to materialize.

F. *RPM Recognizes the Value of Capacity That Helps the System Operator Meet Operational Reliability Requirements*

RPM also provides an appropriate vehicle to help address the decline in load-following and thirty-minute-start capabilities, as detailed above. RPM will encourage the investment needed to maintain and expand these capabilities.

Specifically, the RPM auction-clearing algorithm will produce higher compensation for Load-Following Resources and Thirty-Minute-Start Resources to the extent needed to meet the system's requirements for such resources. Prior to the RPM auctions, PJM will determine the region's minimum requirement for each of these types of resources, and certify units capable of meeting those requirements. Market sellers with such resources can specify in their offers the added price, if any, they desire to offer these capabilities. If either of the operational reliability constraints bind in the auction, then the price will clear higher as necessary to ensure the minimum required amount of resources, with such capability, are committed in the auction. All generation resources in the region that provide that needed capability then will receive the same price adder.[99]

To ensure the capability is provided, resources committed in the auctions to resolve the operational reliability constraints must pass capability tests in the Delivery Year, and must specify and offer such capabilities in their offer data for the PJM energy market.

---

99 The adder may differ for the two capabilities, i.e., Load-Following versus Thirty-Minute-Start. If the Load-Following constraint binds in the auctions, all Load-Following resources will receive the adder for that constraint; and if the Thirty-Minute-Start constraint binds, all Thirty-Minute-Start resources will receive that adder.

G. *RPM Promotes Long-Term Investment in Demand-Side Resources*

Consistent with the Commission's policy of encouraging demand response,[100] RPM will promote demand response by creating new forward revenue streams that will facilitate investment in demand resources. RPM also preserves the current option of allowing LSEs to mitigate capacity obligations through demand response solutions certified as late as three months before the Delivery Year. Establishing a forward revenue stream option will encourage creative demand response providers and plant operators to develop long-term solutions that capture those revenues, reduce energy costs, and improve their bottom line. Moreover, by allowing load-response resources the opportunity to bid competitively to satisfy system reliability requirements, the region as a whole will realize reliability-cost savings whenever those solutions are more cost-effective than generation or transmission alternatives.

As the Commission has recognized, "removing barriers for demand response resources to participate in regional transmission organization markets" encourages demand response.[101] RPM does just that by enabling the participation of demand response resources in PJM's capacity market. Under RPM, a load serving entity's capacity obligation (i.e. the "Daily Unforced Capacity Obligation") can be satisfied with existing and planned demand resources and Interruptible Load for Reliability ("ILR"), as well as generation resources.[102]

---

100 See e.g., PJM Interconnection, 109 FERC ¶ 61,379 at P 1, (2004) (accepting tariff revisions creating a special membership for parties wishing to participate in the PJM real time economic load response because it "benefits customers by encouraging demand response."); PJM Interconnection, 108 FERC ¶ 61,302 at P 12 ("Commission finds that behind-the-meter tariff provision . . . is consistent with our policy of encouraging demand response programs."); PJM Interconnection, L.L.C., 107 FERC ¶ 61,113, at P 27 (2004) ("[C]onsistent with our policy of encouraging demand response programs, PJM's market rules are just and reasonable and will encourage qualifying entities with behind the meter generation to reduce their use of the PJM transmission system."); see also Midwest Indep. Transmission Sys. Operator, Inc., 108 FERC ¶ 61,163, at P 442 (2004).

101 PJM Interconnection, 109 FERC at P 7.

102 See PJM RAA § 1.6; Attachment Y § 5.5.

Both existing and planned Demand Resources can participate in the RPM auctions (both the Base Residual Auctions and Incremental Auctions), which commit resources years or months in advance to satisfy capacity obligation in a Delivery Year.[103] Demand resources (and ILR, discussed below), will be paid the base capacity price in the PJM Region, plus any Locational Price Adders for the LDA in which the resource is located,[104] to help get resources into constrained LDAs in a timely and cost-effective manner.

Participation in the RPM auctions will provide demand response participants with a future revenue stream on which they can rely to aid their installation or expansion of demand resources. As explained in more detail in Appendix A, the Base Residual Auction commits resources for a Delivery Year and guarantees the payment of auction clearing prices for those committed resources four years in advance. Similarly, the Incremental Auctions commit resources and guarantee revenues 23 months, 13 months, and four months prior to a Delivery Year. Demand Resources can incorporate these future guaranteed revenues into their planning processes to create new load-reducing capabilities, or enhance existing capabilities. Stated differently, these guaranteed revenues will spur greater capital investment in demand resources and encourage more demand response.

In addition to the RPM auctions, demand resources may receive revenues for load reductions as ILR. Rather than participate in the four-year forward auctions, ILR Providers[105] will receive compensation for demand response as much as market

---

103 Attachment Y § 5.4.

104 See id. § 5.13, PJM RAA, Sch.6 § 8.D. However, Demand Resources and ILR do not receive any operational reliability adders. Such resources do not provide Load Following or Thirty-Minute-Start capabilities, which are generation-based products. If an LSE has a unit that provides such capabilities, and seeks capacity revenues for that unit, then it must offer it into both the capacity and energy markets, so that PJM can call upon those capabilities.

105 An "ILR Provider" is a PJM member "that has the capability to reduce load, or aggregates customers capable of reducing load." Id. § 2.26.

participants do today through PJM's Active Load Management ("ALM") rules. Maintaining this existing participation alternative will ensure that existing Demand Response participation does not diminish and thus will engender a more robust competitive capacity market.

Under this option, an ILR Provider can submit a resource for certification by PJM as late as three months prior to a Delivery Year. If the resource is certified, the ILR provider will receive the Zonal Capacity Price[106] during the Delivery Year for the zone where its resource is based.

As Mr. Ott explains, because RPM establishes capacity values for each year up to four years ahead, a customer that elects to participate as ILR in a given Delivery Year will know the value of capacity in PJM not only for that upcoming year but also for each of the next three years. This revenue certainty will help load response providers or end use customers plan and implement the most cost effective load management processes or strategies. Therefore, even a customer that is reluctant to commit its load-response capability as a resource in an RPM auction still will have options under RPM to receive several years of capacity revenues (in the form of an ILR credit against the LSE capacity payment otherwise due in each of those years). And it can wait until after the results of the RPM auctions are known before making those resource plans. As a further option, the LSE could choose to offer its load-response capability into one of the incremental auctions for the Delivery Year as a Demand Resource, to see if it can improve the value of its resource compared to being ILR as established in the base residual auction.

H. RPM Permits Transmission Solutions to Compete Directly with Generation Solutions to Resolve Locational Constraints at Lowest Cost

RPM greatly enhances the integration of capacity adequacy and PJM's regional transmission planning process. As noted, locational constraints identified in the planning process will determine the capacity pricing areas used in the auctions. The forward-looking transmission planning process will now be partnered with a comparably forward-

[106] Less any Operational Price Adder, since demand resources do not provide these capabilities.

looking capacity commitment process, allowing market participants in each process to take account of developments in the other. PJM will aid this process by developing for, and sharing with, RPM auction participants longer-range forecasts than are currently available in the RTEP five year plan, identifying areas that may be trending toward reliability violations beyond five years, so that bids and offers (as well as bilateral contracts) can take account of expected long-term trends.

In addition, RPM will create direct opportunities for transmission upgrades to resolve local import concerns more efficiently than local generation, further reducing the likelihood of future reliance on out-of-market compensation. In addition to existing or planned generation projects, and existing or planned load response projects, RPM will allow planned transmission upgrades that provide incremental increases in import capability into constrained areas to be offered into the auctions. This will provide direct competition between generation and transmission solutions to meet the region's future reliability needs.

As Mr. Herling explains (at pages 14-15 of his affidavit), to participate in an RPM auction, a planned transmission upgrade must:

(1) Increase the Transfer Limit into an LDA;

(2) Demonstrate it will be in service on or before the first Delivery Year for which it is offered; and

(3) Be funded by a customer or owner through a rate specific to the facility.

The last requirement ensures that a party receiving RPM revenues for a transmission upgrade is the party that bore the cost of the upgrade.

When a seller offers a transmission upgrade into an RPM auction, it will state its offer price in terms of a price difference between a Capacity Resource located outside the LDA and a Capacity Resource located inside the LDA. This allows for direct comparison between the benefits offered by the transmission upgrade versus the benefits offered by competing generators. A transmission upgrade will compete directly with a proposed new generator to be built inside a constrained LDA to capture the Locational Price Adder that will be paid by loads inside the LDA. The market participant—transmission, generation, or Demand Resource—that offers the lowest Locational Price Adder needed to satisfy loads in the LDA will set the clearing price for the auction, and all sellers—transmission, generation, and Demand Resource—offering up to that price will clear.

When a transmission upgrade clears in the RPM auction, the seller will receive payments during the Delivery Year equal to the cleared Locational Price Adder times the MW amount by which the upgrade increased the transfer limit into the LDA.

As designed, these rules give a single market participant the option of combining a generator located outside a constrained LDA with a transmission upgrade that increases the Transfer Limit into the LDA, so that the external generator can compete to satisfy loads in the LDA. Of course, as described above, the party offering the transmission upgrade also may be completely independent of any seller of generation, and need not specify the source of the energy that will be brought into the constrained area in order to participate in the LDA market.

I. ***RPM Supports Bilateral Contracting***

Importantly, RPM is compatible with, and will promote, bilateral contracts. Under RPM, LSEs will designate their self-supplied and bilaterally contracted resources before the first auction. When so designated by the LSE, that capacity will be included at zero price in the supply curve that is cleared against the VRR. The RPM auctions will commit only those additional capacity resources needed to satisfy load obligations that are not already covered by bilateral contracts or self-supply.[107] RPM's four-year-forward approach also will encourage parties to enter into new long-term contracts, or extend existing contracts. The RPM auctions will produce transparent reference prices that then will inform bilateral contract prices.

There will be some transition matters to address for bilateral contracts as a result of new locational capacity pricing, just as there were transition matters to address when LMP was introduced in energy markets. However, just as it did with LMP, PJM will facilitate this transition through the establishment of capacity trading hubs,[108] sponsoring

---

107 LSEs that elect the bilateral or self-supply alternative will be subject only to capacity price differences, if any, between their specified resources and their load obligations.

108 Such hubs will continue beyond the transition, just as the PJM energy market today uses hubs.

stakeholder forums on transition matters, standardizing contract reforms, and through internet based bilateral capacity trading systems. Moreover, as discussed in more detail below, RPM phases in its locational and operational reliability aspects precisely to give market participants additional time to adapt their pre existing agreements.

Just as occurred with LMP, bilateral transactions can be expected to integrate new pricing information and approaches and flourish.

J. <u>*RPM Provides Appropriate Protection Against the Exercise of Market Power*</u>

RPM includes explicit rules governing market power mitigation in the capacity market. This is an important benefit of the RPM proposal, as PJM's existing capacity market does not include explicit market power mitigation rules. Given that RPM has the potential to increase the ability to exercise market power, e.g., through the creation of smaller, regional capacity markets, this explicit set of market power mitigation rules is central to RPM. Nonetheless, the RPM market power mitigation rules are designed to minimize intervention in the capacity markets.

Section 6 of new Attachment Y to the PJM Tariff sets forth the market power mitigation provisions applicable to the RPM auctions. Before an RPM auction, PJM will identify whether the PJM Region or any constrained LDAs may be subject to mitigation in the RPM auction; generators in such areas will have to provide additional information that PJM can use in case mitigation is applied.[109] In the ensuing Base Residual Auction, before the final determination of clearing prices, PJM will apply a market structure test to any constrained LDA to determine whether mitigation in the LDA in fact is warranted.[110]

---

[109] Preliminary market structure screens will be based on the Unforced Capacity available for the Delivery Year from Generation Capacity Resources located in an LDA, the Locational Deliverability Area Reliability Requirement, and any firm obligations to sell Unforced Capacity from Generation Capacity Resources (including bilateral contracts) for the Delivery Year. Attachment Y § 6.3(a)(i). An LDA will be considered potentially subject to mitigation if the market share of any seller is greater than 20 percent, the HHI for all sellers is 1800 or higher, or there are not more than three jointly pivotal suppliers. Id. § 6.3(a)(ii).

[110] <u>Id.</u> § 6.2.

To make this determination, PJM will apply a three pivotal supplier test. PJM will analyze sell offers that would resolve the constraint in the LDA, and if there are not more than three jointly pivotal suppliers, PJM will apply offer caps (discussed below) and clear the auction with the offer caps in place. The three pivotal supplier test is consistent with the market power test used in the energy market; however, PJM recognizes that this test is under investigation in a pending proceedings before the Commission, and will modify it here as and if necessary as a result of the Commission's action in that proceeding.

If the LDA fails the three pivotal supplier test, offer caps will be imposed.[111] Offer caps will be applied to Generation Capacity Resources on a unit-specific basis only if the resource's offer for unforced capacity is greater than offer cap applicable to the resource and would, absent mitigation, increase the Zonal Clearing Price in the relevant auction.[112] The Generation Resource's offer cap will be its avoidable cost rate less its projected PJM Market Revenues[113] for points on the seller's offer curve included in its Base Offer Segment, and the Net Cost of New Entry for points on the curve within its EFORd Offer Segment.[114] In the event, however, that the Generation Capacity Resource can document an available price external to PJM for its capacity, PJM ranks such offers and accepts the most competitive offers for export which qualify for an offer cap based on such opportunity costs.[115]

---

111 See id. § 6.3(b)(ii).

112 Id. § 6.5(a)(i). Offer caps will not be applied to sell offers of planned generation resources or planned demand resources. Id. § 6.5(a)(ii) & (b).

113 Projected PJM Market Revenues include all unit-specific revenues from the PJM markets and bilateral contracts net of marginal costs recoverable under cost-based offers to sell energy. Id. § 6.7 (c)(iv).

114 Id. § 6.4(a).

115 Id. If the total megawatts of existing generating resources submitting opportunity cost offers in any auction exceeds PJM's firm export capability, or the external market's firm import capability, then the availability of opportunity-cost pricing will be apportioned among those offers, taking the most competitive opportunity cost offers first. Id. § 6.7(c)(ii).

The Avoidable Cost Rate for a Generation Capacity Resource is determined using essentially the same formula that the Commission accepted for determining the Deactivation Avoidable Cost Rate for units slated for deactivation that continue to operate past their desired deactivation date.[116] For the purpose of determining the Avoidable Cost Rate for a Generation Capacity Resource, avoidable expenses are incremental expenses directly required for the operation of the generation unit that a Generation Owner would not incur if such generating unit did not operate in the Delivery Year, plus a ten percent adder.[117] As Mr. Bowring explains (at p. 24), the ten percent adder is not intended to include a profit in the definition of avoidable costs, but to recognize the uncertainty associated with the exact measurement of avoidable costs for a period four years in the future. The RPM avoidable cost rate offer cap also includes a fixed cost component or "capital recovery factor" that addresses the costs associated with incremental capital investments at a unit.

As mentioned above, units are offer capped at their Avoidable Cost Rate for points on the bid curve included in its Base Offer Segment.[118] As explained by Mr. Bowring (at pages 20-22 of his affidavit) an offer cap based on a unit's avoidable costs is an appropriate offer cap up to its Base Offer Segment because avoidable costs represent a competitive offer for a capacity resource. Market seller offer caps are intended to reflect competitive offers for capacity resources, recognizing that capacity in the RPM construct is fundamentally an annual product. At the most basic level, a competitive offer for an annual offer of capacity is the annual avoidable cost of the unit, less net revenues from other PJM markets, including the bilateral sale of any product from the unit. This is a competitive offer because it reflects the incremental cost of capacity for a year. A rational seller would not offer capacity into a competitive capacity market for less than the avoidable costs less net revenue from other markets or for more than that value.

---

116 See PJM Interconnection, 110 FERC at P 104; PJM Tariff § 115; see also Attachment Y § 6.8(a).

117 Attachment Y § 6.8(c).

118 Id. § 6.4(a).

The RPM mitigation rules established a higher offer cap for the unit's points on the bid curve within its EFORd Offer Segment.[119] This higher offer cap is the Net Cost of New Entry. This higher offer cap is appropriate because the EFORd Offer Segment of a generating unit's offer addresses the risk of change in the unit's EFORd between the auction and the Delivery Year. The net CONE is selected as the offer price for the EFORd Offer Segment to reflect the risk to a generation owner that the EFORd applicable to the Delivery Year may exceed the EFORd used to determine the level of MW offered into the Base Residual Auction. In that case, the generation owner would have sold more MW in the Base Residual Auction than it actually had available for the Delivery Year, and would have to purchase the difference in an incremental auction. The CONE is used to reflect the risk that the owner could face a high price for the EFORd related difference in the final incremental auction.

Physical withholding is a potentially profitable strategy for exercising market power in the aggregate market or in local markets. In addition to mitigation of economic withholding through offer capping, the RPM market power mitigation rules protect against the exercise of market power by providing disincentives to the physical withholding of capacity. Section 6.6 of Attachment Y requires that all Generation Capacity Resources offer their unforced capacity into the Base Residual Auction for the Delivery Year. Section 6.6 further provides that all generating units that qualify as Generation Capacity Resources cannot avoid participation in the RPM auctions by declining to so qualify their units, unless the resource reasonably expected to be physically unable to participate in the relevant Delivery Year, has a physically firm commitment to an external sale of its capacity, or originally was interconnected to the PJM transmission system only as an Energy Resource, and remains an Energy Resource. A Generation Capacity Resource that violates these rules will not be able to participate in any subsequent auctions for the relevant Delivery Year; it will not receive payments pursuant to section 5.14 (Clearing Prices and Charges) for the Delivery Year; and it will not be permitted to use the withheld capacity to meet any entity's capacity obligation for

[119] Id.

the relevant Delivery Year.[120] Finally, if PJM determines that the failure of one or more Capacity Market Sellers to offer part or all of one or more existing generation resources into an RPM auction would result in an increase of greater than five percent in any Zonal Capacity Price determined through such auction, compared to the price that would have resulted absent that withholding, then PJM shall apply to the Commission for an order, on an expedited basis, directing such Capacity Market Seller to participate in the auction (or for other appropriate relief). In such a case, PJM will postpone clearing the affected auction pending the Commission's decision.[121]

K. *RPM Ensures that Market Participants Honor their Capacity Commitments*

Like PJM's current capacity construct, RPM includes various charges to ensure that market participants honor their commitments. Because RPM expands the number and type of resources that can be committed in the capacity auctions (e.g., planned resources, demand resources, transmission upgrades, and operational reliability resources), the tariff adds enforcement charges appropriate to these various resources. These charges are set forth in Sections 7, 8, 9, 10, 11, and 12 of Attachment Y.

Section 7 assesses a Generation Resource Rating Test Failure Charge if a committed generation resource fails a generation resource capacity test. Section 8 assesses a Capacity Resource Deficiency Charge if a committed Capacity Resource is unable to deliver Unforced Capacity, for such reasons as a unit derating, EFORd increase, or failure to put a planned resource in operation by the start of the Delivery Year, and the seller does not obtain sufficient replacement capacity. A demand resource that cannot provide the load reduction capability committed in the auction will be assessed the Schedule 8 charge, unless it can show that the inability is due to the permanent departure of load from the transmission system.

Section 9 provides a peak season maintenance compliance penalty, similar to a charge in effect under the RAA today. Section 10 assesses a penalty if a resource

---

120 See e.g., id. § 6.6 (d).

121 Id. § 6.6(g).

committed as a load-following resource or thirty-minute-start resource fails to satisfy capability tests, or if the seller fails to list the operational reliability attributes in its offer data in the energy market. Section 11 assesses a demand resource and ILR Compliance Penalty charge if a provider cannot demonstrate the hourly performance of its committed demand resource or certified ILR in real time based on the commitment reflected in its sell offer or certification. Section 12 provides for an emergency procedure charge, similar to today.

L. ***RPM Includes Reasonable Transition Provisions***

RPM includes transition provisions, developed based on feedback from the stakeholder process, to gradually implement the four-year forward commitment period, locational constraints, and operational reliability constraints. This transition period will provide the opportunity for market participants to adapt existing contracts to the RPM design.

RPM generally provides that the first auction to commit capacity resources for a Delivery Year will be four years before the start of the Delivery Year, followed by Incremental Auctions at various times over that four year periods. Section 17 of Attachment Y sets forth a schedule to phase in these auctions for the near term Delivery Years from 2006 to 2010. During this period, PJM will expedite the generation interconnection process for new resources to facilitate their participation as competing resources in RPM. PJM recognizes that, because the time between the initial auctions and the delivery years for these "transitional" years will be less than four years, the strength and value of the forward component of RPM will be correspondingly diminished. PJM nevertheless believes that providing revenues to resources during this period will help build confidence in the new capacity market, discourage retirements or mothballing of plants that may be needed, and provide valuable experience in market behavior. Moreover, in light of the current general surplus of capacity within PJM, and the phasing in of the LDAs, the costs imposed by these transitional auctions are likely to be modest.

Locational constraints will be phased in gradually over the first two auctions to reduce the impact on existing bilateral contracts. Section 17 of Attachment Y establishes two large subregions of PJM as Locational Deliverability Areas for the first Delivery Year (2006-2007); adds two more LDAs for the second year (2007-2008); and then specifies the full complement of LDAs for the next two years (2008-2009 and 2009-2010). This approach was designed through the stakeholder process to acknowledge the impact that RPM may have on the state retail auctions in New Jersey and Maryland, and to minimize the impact on bilateral contracts effective during the 2006 and 2007 Delivery Years.

As another accommodation to allow market participants ample time to adapt their current agreements, RPM provides that the Operational Reliability Requirements will not apply in those first two Delivery Years.

On another transition issue, section 14 of Attachment Y establishes rules for financial settlement of capacity credits created under Schedule 11 of the Operating Agreement, which will not be accepted to satisfy capacity obligations under RPM.

M. RPM Includes Reasonable Backstop Provisions to Ensure Reliability

The Commission has held that RTO resource procurement, whether long-term contracts or direct procurement of generation, should only be used as a backstop mechanism when no reasonable market design improvements can bring about investment in needed generation. [122]

RPM includes such a backstop mechanism, and it includes a high hurdle for PJM intervention. The backstop is triggered only if a shortage[123] is observed in the auctions for four consecutive Delivery Years,[124] and only subject to the Commission approval.

As Mr. Ott explains (at pp. 32-33 of his affidavit), if PJM administers four consecutive base residual auctions in which insufficient capacity is committed, then PJM

---

[122] PJM Interconnection, L.L.C., 110 FERC ¶ 61,035, at P 64 (2005).

[123] For this purpose, a capacity shortage refers to an auction result where all capacity cleared equates to a reserve margin that is more than one percentage point lower than the IRM target set by the PJM Board; or clearing of base load generation capacity at a level less than the minimum hourly load forecast for the Delivery Year at issue.

[124] Attachment Y § 16.2.

will file with FERC for approval to conduct a reliability backstop auction within four months after the last such base residual auction. The reliability backstop auction will seek commitments of additional generation resources for a term of up to fifteen years, based on the sell offer(s) that satisfy the posted reliability requirements at the lowest price. If a seller's offer is accepted in the Reliability Backstop Auction, then PJM will enter into a long-term purchase agreement (on behalf of all LSEs in the PJM Region) with that seller. Under this agreement, the seller will be paid its offer price, less any payments the seller is entitled to receive for commitment of the same resource through the regular RPM auctions, and less any contributions to the fixed cost of its resource from the energy or ancillary service markets. The resulting agreement will be filed with FERC. PJM will recover the costs of such payments through a charge assessed on all LSEs pro rata based on their RPM capacity obligation.

A seller whose offer is selected in the backstop auction must offer all capacity of its resource into the Base Residual Auctions held after the backstop, for all delivery Years in the term of its offer. The seller must offer such resources at zero price, and will receive the clearing price determined in each such auction.

PJM believes that the structure of RPM will make the backstop mechanism the rare exception rather than the rule. Should that expectation be disappointed, however, and the backstop required on a regular basis, PJM would re-examine the RPM market structure, and submit appropriate changes to the Commission.

VI. THE CONFORMING CHANGES TO THE TARIFF AND OPERATING AGREEMENT ARE REASONABLE AND NECESSARY

In addition to the changes discussed above, RPM involves certain other conforming changes to the PJM Tariff and Operating Agreement.

A. *Revisions to PJM Tariff Attachment Q—PJM Credit Policy*

Attachment Q to the Tariff sets forth PJM's credit policy. Under the current provisions of Attachment Q, a market participant's credit requirement is based on its peak market activity, and that activity will now include cleared positions resulting from the RPM Auctions. In addition, the revisions to PJM's credit policy address the additional credit exposure stemming from market sellers making future commitments through the RPM auctions based on resources for which there is a materially increased risk of non-performance, such as planned generation or demand resources, or existing external resources that have not yet secured the firm transmission they require to deliver to the PJM Region on a firm basis.

This additional credit requirement, unique to the four-year forward commitments inherent in RPM, will be reduced as the associated uncertainties are resolved, i.e., by securing firm transmission for an external unit, qualifying a planned demand resource as a capacity resource, or meeting key project milestones for a planned generation resource.

B. ***Revisions to PJM Tariff Schedule 9-5—Capacity Resource and Obligation Management Service***

Schedule 9-5 is the mechanism by which PJM recovers its costs of administering the capacity obligation and capacity resource programs. The charge currently is assessed to LSEs, based on their Accounted for Obligations, and on owners of Capacity Resources, based on their megawatts of Unforced Capacity. The schedule is revised to use the revised terminology and revised billing determinants under RPM, but the schedule's structure and basic rate methodology are unchanged. LSEs will now be assessed the administrative charge based on their Daily Unforced Capacity Obligations, and Capacity Market Sellers will be assessed the charge based on their megawatts of Unforced Capacity committed through the RPM auctions.

C. ***Other Miscellaneous PJM Tariff Revisions***

RPM requires a number of other conforming changes to the PJM Tariff. For the most part, these involve replacing the term "Capacity Resource" with the term "Generation Capacity Resource" where the context is limited to generation units. Most of these changes appear in Part IV of the Tariff, concerning PJM's generation interconnection rules.

D. *Miscellaneous Operating Agreement Changes*

RPM requires a number of conforming changes to the PJM Operating Agreement. Definitions are added or revised for such terms as Capacity Resource, Demand Resource, Generation Capacity Resource, and Interruptible Load for Reliability. References to the West RAA and South RAA are eliminated, and the term "RAA" is redefined to refer to the new RAA for RPM. Because a Capacity Resource may now include a Demand Resource, references in the Operating Agreement to Capacity Resources, where the existing context involves a generation unit, are replaced with the term "Generation Capacity Resource." Several changes are made to the offer specification rules in section 1.10 of Schedule 1 of the Operating Agreement, to coordinate those rules with the resource commitments made through the RPM auctions, including demand resources and operational reliability resources. References to ALM in the existing demand response programs are replaced with the new term, "ILR."

Existing Schedule 8, which describes the delegation of reliability responsibilities to PJM under the existing RAA for MAAC is broadened to refer to the entire PJM Region, under the new single RAA. The delegated responsibilities are unchanged. Schedules 8A and 8B, which describe the delegation of reliability responsibilities to PJM under, respectively, the West RAA and South RAA, are deleted, since Schedule 8 will address the entire PJM REgion. Schedules 9 and 9A, addressing emergency procedure charges under the East RAA and West RAA, respectively, also are deleted, because such charges are fully addressed in new Attachment Y. Schedule 11, which sets forth the rules for the existing capacity credit markets, also is deleted, because those credit markets no longer are needed under RPM.

VI. EFFECTIVE DATE

PJM proposes to replace its current capacity construct with RPM on June 1, 2006, which is the first day of the next PJM planning period. To that end, PJM requests that the Commission issue its final order on this filing no later than January 31, 2006.[125] Action

---

125 To the extent the Commission requires additional time to process the section 206 request in this filing, PJM consents to an effective date for the tariff and RAA sheets submitted under section 205 that coincides with the effective date the Commission establishes under section 206 for the operating agreement changes.

by this date will provide certainty to market participants and ensure that PJM has sufficient time before the start of the next planning period to hold the RPM auctions used to determine the cost of capacity for that period. If the Commission does not act until after that date, then PJM likely will not be able to implement RPM in the annual period that runs from June 1, 2006 to May 31, 2007. Consistent with this approach, the enclosed tariff revisions related to conducting the auctions have an effective date of February 1, 2006, while the remainder of the tariff changes have an effective date of June 1, 2006.[126]

VII. DOCUMENTS ENCLOSED

PJM encloses with this transmittal letter the original and six copies of the following :

Tab

A	Illustrative business rules for a Capacity Resource Plan option under RPM
B.	the new PJM RAA
C.	Revised pages of the PJM Tariff (in revised and redline form);
D	Revised pages of the PJM Operating Agreement (in revised and redline form)
E.	Affidavit of Andrew L. Ott, PJM Vice President of Market Services;
F	Affidavit of Steven R. Herling, PJM Vice President of Planning;
G	Affidavit of Joseph E. Bowring, Market Monitor for the PJM Region;
H	Affidavit of Professor Benjamin F. Hobbs of the Johns Hopkins University;
I	Affidavit of Ray L. Pasteris, President of Strategic Energy Services, Inc.
J	Federal Register Notice (also enclosed on diskette).

126 As both of these proposed effective dates are more than 120 days after the date of this filing, PJM requests waiver of section 35.3 of the Commission's rules. Waiver is appropriate, as PJM is filing well in advance of the proposed effective dates to allow the Commission time to process the filing before it takes effect.

VIII. CORRESPONDENCE AND COMMUNICATIONS

Correspondence and communications with respect to this filing should be sent to the following persons:

Craig Glazer
Vice President – Federal Government Policy
PJM Interconnection, L.L.C.
1200 G Street, N.W.
Suite 600
Washington, D.C. 20005
(202) 393-7767
glazec@pjm.com

Barry S. Spector
Paul M. Flynn
Carrie L. Bumgarner
Wright & Talisman, P.C.
1200 G Street, N.W.
Suite 600
Washington, D.C. 20005
(202) 393-1200
spector@wrightlaw.com
flynn@wrightlaw.com
bumgarner@wrightlaw.com

Vincent P. Duane
Senior Regulatory Counsel
PJM Interconnection, L.L.C.
955 Jefferson Ave.
Norristown, PA 19403
(610) 666-4367
duanev@pjm.com

IX. SERVICE

PJM respectfully requests waiver of the posting requirements of 18 C.F.R. § 35.4, to permit electronic distribution of this filing. Consistent with the electronic service rules[127], PJM has posted a copy of this filing, with all attachments, to its internet site, and has e-mailed a link to that document to all PJM Members, and all state commissions in the PJM Region.

Good cause exists for granting this waiver, as it is consistent with the Commission's objective in Order No. 653 to eliminate the use of paper, and it reduces administrative expense and burdens. Many parties, in fact, prefer receiving their copy in electronic format. In addition, paper copies will be made available to any person upon request by contacting counsel of record.

---

[127] Elec. Notification of Comm'n Issuances, Order No. 653, 111 F.E.R.C. P61,021 (2005).

A form of notice suitable for publication in the Federal Register is attached.

Respectfully submitted,

Paul F. Flynn

Craig Glazer
Vice President – Federal Government Policy
PJM Interconnection, L.L.C.
1200 G Street, N.W.
Suite 600
Washington, D.C. 20005
(202) 393-7767
glazec@pjm.com

Barry S. Spector
Paul M. Flynn
Carrie L. Bumgarner
Wright & Talisman, P.C.
1200 G Street, N.W.
Suite 600
Washington, D.C. 20005
(202) 393-1200
spector@wrightlaw.com
flynn@wrightlaw.com
bumgarner@wrightlaw.com

Vincent P. Duane
Senior Regulatory Counsel
PJM Interconnection, L.L.C.
955 Jefferson Ave.
Norristown, PA 19403
(610) 666-4367
duanev@pjm.com

Counsel for
PJM Interconnection, L.L.C

K:\pjm\RPM\Documents\RPM Trnsmtl Ltr.doc

TAB A

Capacity Resource Plan Alternative Illustrative Business Rules

Business Rules for Long Term Capacity Opt-out Alternative to the RPM Auction Process

Purpose: Provide all Load Serving Entities with the option to submit a long-term Capacity Resource Plan as an alternative to the requirement to participate in the PJM Resource Adequacy Construct, RPM.

Requirements:

Load Serving Entity must indicate its intention to opt out of the RPM process for a specific delivery year no later than February 1 of the year four years preceding the start of the June 1 to May 31 delivery year. The Load Serving Entity must give PJM an updated five-year Capacity Resource Plan (covering the delivery year and the four years preceding it) no later than April 1 for the five year planning cycle beginning on June 1.

The long-term Capacity Resource Plan shall cover the upcoming five year planning horizon beginning with June 1 of the current year. If the entity that elected to opt-out of the capacity market fails to designate sufficient generation, prior to April 1, to cover its entire Long-term Installed Capacity Requirement based on its designated load for each year, the entity shall not be eligible to opt-out of the RPM capacity market for only a portion of its load obligation.

The long-term Capacity Resource Plan shall specify the following for each year:

[each year information is covered by the following]

1. Designated Load that will be covered by the resource plan (transmission zone, megawatt portion of the Preliminary Zonal Peak Load Forecast to be served)

2. Designated Generation Resources (unit specific) and Demand Resources that will cover the Long-term Installed Capacity Requirement for the specified peak load (Unit name, zone, Unforced Capacity in megawatts).

3. Any Planned Transmission upgrades that are required to ensure that the Designated Generation Resources will satisfy PJM Generation Deliverability requirements into the LDA. The upgrades would allow the use of capacity external to a zone to satisfy the zonal internal requirement.

If the Load Serving Entity specifies a load obligation in a zone that is in a constrained Locational Deliverability Area (LDA), the entity must include an appropriate percentage of its Designated Generation Resources that are inside the LDA. This required percentage of generation resources that must be in the LDA is specified in advance by PJM.

Entities that elect to opt-out of the capacity market shall designate sufficient generation as Capacity resources to cover their peak load obligation including a long-term installed capacity requirement, which is the sum of the annual Installed Reserve Margin (designated by the PJM Board) plus the reserve margin uncertainty associated with forward commitment. This requirement will ensure that these entities contribute equivalent installed generation to the market as those entities participating in the RPM auction. The reserve margin uncertainty is equal to 1 3.0%.[1].

During the Delivery Year, a Load Serving Entity that elected to opt-out of the capacity market must satisfy its Daily Unforced Capacity Obligation based on generation that was designated in its long-term Capacity Resource Plan. The Daily Unforced Capacity Obligation of such LSE equals the LSE's megawatt portion of the Preliminary Zonal Peak Load Forecast to be served, multiplied by the Forecast Pool Requirement. Even though more reserve than IRM is specified for opt-out, only the basic IRM is used to determine the obligation for compliance. The Forecast Pool Requirement (FPR) for the Delivery Year is calculated by PJM and is equal to the (1 + Annual Installed Reserve Margin) times (1-Pool-wide Average EFORd). If the LSE fails to satisfy their Daily Unforced Capacity Obligation in each zone with its long-term Capacity Resource Plan, the LSE shall pay a daily capacity deficiency charge equal to two times the Cost of New Entry multiplied by the Daily Unforced Capacity Obligation shortfall in each zone. The excess capacity in a zone cannot be used to cover the capacity deficiency in another zone.

If the opted-out LSE acquires new load that is not included in the original Designated Load, it cannot use the excess from the long-term Capacity Resource Plan to meet the obligation associated with the new load, as PJM has already procured resources to meet this load obligation. The LSE will have to pay the Locational Reliability Charge for this incremental load obligation.

Generators that are designated in the long-term Capacity Resource Plan shall be subject to the same performance requirements as PJM Designated Capacity Resources for the five-year period. The Unforced Capacity value of the generators for the Delivery Year will be determined using the 12-month rolling average EFORd based on forced outage data from the October through September period prior to the Delivery Year.

Generators that are designated in the long-term Capacity Resource Plan are required to be PJM capacity resources for the entire five-year period (cannot be de-listed) and they are not eligible to receive PJM Capacity payments during this period. Any capacity resources, including transmission and demand resources, that are designated in the long-term Capacity Resource Plan are not eligible to be sold as capacity resources in any PJM capacity auction for the five-year period.

Generators that are designated in the long-term Capacity Resource Plan are not eligible to be used as Installed capacity resource for any other entity other than the entity specified in the long-term Capacity Resource Plan.

---

[1] This uncertainty has two components. The first component is the 1% uncertainty required for the forward generation commitment (this is the 1% offset on the variable resource requirement.) The second component is the four year load forecast uncertainty which was calculated to be 2.0% based on the established probabilistic analysis methods. .

TAB B

The New PJM RAA

Reliability Assurance Agreement

Among Load-Serving Entities

In the PJM Region

K pjm RPM Documents RAA for RPM (08-30-05) doc

RELIABILITY ASSURANCE AGREEMENT

Among

LOAD SERVING ENTITIES

in the

PJM REGION

RELIABILITY ASSURANCE AGREEMENT

RELIABILITY ASSURANCE AGREEMENT, dated as of this 1st day of June, 2006 by and among the entities set forth in Schedule 16 hereto, hereinafter referred to collectively as the "Parties" and individually as a "Party."

WITNESSETH:

WHEREAS, each Party to this Agreement is a Load Serving Entity within the PJM Region;

WHEREAS, each Party is committing to share its Capacity Resources with the other Parties to reduce the overall reserve requirements for the Parties while maintaining reliable service; and

WHEREAS, each Party is committing to provide mutual assistance to the other Parties during Emergencies;

WHEREAS, each Party is committing to coordinate its planning of Capacity Resources to satisfy the Reliability Principles and Standards;

WHEREAS, the Parties previously have entered into similar commitments related to sub-regions of the PJM Region through the East RAA, the West RAA, or the South RAA;

WHEREAS, the Parties desire, on a phased basis, to replace the East RAA, West RAA, and South RAA with a single reliability assurance agreement among all Load-Serving Entities in the PJM Region; and

NOW THEREFORE, for and in consideration of the covenants and mutual agreements set forth herein and intending to be legally bound hereby, the Parties agree as follows:

ARTICLE 1 -- DEFINITIONS

Unless the context otherwise specifies or requires, capitalized terms used herein shall have the respective meanings assigned herein or in the Schedules hereto for all purposes of this Agreement (such definitions to be equally applicable to both the singular and the plural forms of the terms defined). Unless otherwise specified, all references herein to Articles, Sections or Schedules, are to Articles, Sections or Schedules of this Agreement. As used in this Agreement:

1.1 Agreement shall mean this Reliability Assurance Agreement, together with all Schedules hereto, as amended from time to time.

1.2 Applicable Regional Reliability Council shall have the same meaning as in the PJM Tariff.

1.3 Base Residual Auction shall have the same meaning as in Attachment Y to the PJM Tariff.

1.4 Behind The Meter Generation shall mean one or more generating units that are located with load at a single electrical location such that no transmission or distribution facilities owned or operated by any Transmission Owner or Electrical Distributor are used to deliver energy from such generating units to such load; provided, however, that Behind The Meter Generation does not include (i) at any time, any portion of such generating unit[s]' capacity that is designated as a Capacity Resource or (ii) in any hour, any portion of the output of the generating unit[s] that is sold to another entity for consumption at another electrical location or into the PJM Interchange Energy Market.

1.5 Black Start Capability shall mean the ability of a generating unit or station to go from a shutdown condition to an operating condition and start delivering power without assistance from the power system.

1.6 Capacity Resources shall mean megawatts of (i) net capacity from existing or Planned Generation Capacity Resources meeting the requirements of Schedules 9 and 10 that are or will be owned by or contracted to a Party and that are or will be committed to satisfy that Party's obligations under this Agreement for a Delivery Year; (ii) net capacity from existing or Planned Generation Capacity Resources within the PJM Region not owned or contracted for by a Party which are accredited to the PJM Region pursuant to the procedures set forth in Schedules 9 and 10; and (iii) load reduction capability provided by Demand Resources or ILR that are accredited to the PJM Region pursuant to the procedures set forth in Schedule 6.

1.7 Capacity Transfer Right shall have the meaning specified in Attachment Y to the PJM Tariff.

1.8 Control Area shall mean an electric power system or combination of electric power systems bounded by interconnection metering and telemetry to which a common generation control scheme is applied in order to:

(a) match the power output of the generators within the electric power system(s) and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);

(b) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;

(c) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice and the criteria of NERC and Applicable Regional Reliability Councils;

(d) maintain power flows on transmission facilities within appropriate limits to preserve reliability; and

(e) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

1.9 Daily Unforced Capacity Obligation shall have the meaning set forth in Schedule 8.

1.10 Delivery Year shall mean a Planning Period for which a Capacity Resource is committed pursuant to the auction procedures specified in Attachment Y to the Tariff.

1.11 Demand Resource shall mean a resource with a demonstrated capability to provide a reduction in demand or otherwise control load in accordance with the requirements of Schedule 6 that offers and clears load reduction capability in a Base Residual Auction or Incremental Auction. As set forth in Schedule 6, a Demand Resource may be an existing demand response resource or a Planned Demand Resource.

1.12 Demand Resource Provider shall have the meaning specified in Attachment Y to the PJM Tariff.

1.13 DR Factor shall mean that factor approved from time to time by the PJM Board used to determine the unforced capacity value of a Demand Resource or ILR in accordance with Schedule 6.

1.14 East RAA shall mean that certain Reliability Assurance Agreement among Load-Serving Entities in the PJM Region, PJM Rate Schedule FERC No. 27.

1.15 Electric Distributor shall mean an entity that owns or leases with rights equivalent to ownership electric distribution facilities that are providing electric distribution service to electric load within the PJM Region.

1.16 Emergency shall mean (i) an abnormal system condition requiring manual or automatic action to maintain system frequency, or to prevent loss of firm load, equipment damage, or tripping of system elements that could adversely affect the reliability of an electric system or the safety of persons or property; or (ii) a fuel shortage requiring departure from normal operating procedures in order to minimize the use of such scarce fuel; or (iii) a condition that requires implementation of emergency procedures as defined in the PJM Manuals.

1.17 End-Use Customer shall mean a Member that is a retail end-user of electricity within the PJM Region.

1.18 Facilities Study Agreement shall have the same meaning as in the PJM Tariff.

1.19 FERC shall mean the Federal Energy Regulatory Commission or any successor federal agency, commission or department.

1.20 Firm Point-To-Point Transmission Service shall mean Firm Transmission Service provided pursuant to the rates, terms and conditions set forth in Part II of the PJM Tariff.

1.21 Firm Transmission Service shall mean transmission service that is intended to be available at all times to the maximum extent practicable, subject to an Emergency, an unanticipated failure of a facility, or other event beyond the control of the owner or operator of the facility or the Office of the Interconnection.

1.22 Forecast Pool Requirement shall mean the amount, stated in percent, equal to one hundred plus the percent unforced reserve margin for the PJM Region required pursuant to this Agreement, as approved by the PJM Board pursuant to Schedule 4.1.

1.23 Full Requirements Service shall mean wholesale service to supply all of the power needs of a Load Serving Entity to serve end-users within the PJM Region that are not satisfied by its own generating facilities.

1.24 Generation Capacity Resource shall mean a generation unit, or the right to capacity from a specified generation unit, that meets the requirements of Schedules 9 and 10 of this Agreement. A Generation Resource may be an existing Generation Resource or a Planned Generation Resource.

1.25 Generation Owner shall mean a Member that owns or leases with rights equivalent to ownership facilities for the generation of electric energy that are located within the PJM Region. Purchasing all or a portion of the output of a generation facility shall not be sufficient to qualify a Member as a Generation Owner.

1.26 Generator Forced Outage shall mean an immediate reduction in output or capacity or removal from service, in whole or in part, of a generating unit by reason of an Emergency or threatened Emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the facility, as specified in the relevant portions of the PJM Manuals. A reduction in output or removal from service of a generating unit in response to changes in market conditions shall not constitute a Generator Forced Outage.

1.27 Generator Maintenance Outage shall mean the scheduled removal from service, in whole or in part, of a generating unit in order to perform repairs on specific components of the facility, if removal of the facility qualifies as a maintenance outage pursuant to the PJM Manuals.

1.28 Generator Planned Outage shall mean the scheduled removal from service, in whole or in part, of a generating unit for inspection, maintenance or repair with the approval of the Office of the Interconnection in accordance with the PJM Manuals.

1.29 Good Utility Practice shall mean any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather is intended to include acceptable practices, methods, or acts generally accepted in the region.

1.30 ILR Provider shall have the meaning specified in Attachment Y to the PJM Tariff.

1.31 Incremental Auction shall mean the First Incremental Auction, the Second Incremental Auction, or the Third Incremental Auction, each as defined in Attachment Y to the PJM Tariff.

1.32 Interconnection Agreement shall have the same meaning as in the PJM Tariff.

1.33 Interruptible Load for Reliability, or ILR, shall mean a resource with a demonstrated capability to provide a reduction in demand or otherwise control load in accordance with the requirements of Schedule 6 that is certified by PJM no later than three months prior to a Delivery Year.

1.34 Load Following Resource shall mean a Generation Resource that has demonstrated flexible start capability or dispatchable capability pursuant to Schedule 9.1 of this Agreement.

1.35 Load Serving Entity or **LSE** shall mean any entity (or the duly designated agent of such an entity), including a load aggregator or power marketer, (i) serving end-users within the PJM Region, and (ii) that has been granted the authority or has an obligation pursuant to state or local law, regulation or franchise to sell electric energy to end-users located within the PJM Region. Load Serving Entity shall include any end-use customer that qualifies under state rules or a utility retail tariff to manage directly its own supply of electric power and energy and use of transmission and ancillary services.

1.36 Locational Reliability Charge shall mean the charge determined pursuant to Schedule 8.

1.37 Member shall mean an entity that satisfies the requirements of Sections 1.24 and 11.6 of the PJM Operating Agreement. In accordance with Article 4 of this Agreement, each Party to this Agreement also is a Member.

1.38 Members Committee shall mean the committee specified in Section 8 of the PJM Operating Agreement composed of the representatives of all the Members.

1.39 NERC shall mean the North American Electric Reliability Council or any successor thereto.

1.40 Network Resources shall have the meaning set forth in the PJM Tariff.

1.41 Network Transmission Service shall mean transmission service provided pursuant to the rates, terms and conditions set forth in Part III of the PJM Tariff or transmission service comparable to such service that is provided to a Load Serving Entity that is also a Transmission Owner (as that term is defined in the PJM Tariff).

1.42 Nominated Demand Resource Value shall have the meaning specified in Attachment Y to the PJM Tariff.

1.43 Nominated ILR Value shall have the meaning specified in Attachment Y to the PJM Tariff.

1.44 Obligation Peak Load shall be the summation of the weather normalized coincident summer peaks for the previous summer of the end-users for which the Party was responsible on that billing day, as determined pursuant to Schedule 8 of this Agreement.

1.45 Office of the Interconnection shall mean the employees and agents of PJM Interconnection, L.L.C., subject to the supervision and oversight of the PJM Board, acting pursuant to the Operating Agreement.

1.46 Operating Agreement of PJM Interconnection, L.L.C. or **Operating Agreement** shall mean that certain agreement, dated April 1, 1997 and as amended and restated June 2, 1997 and as amended from time to time thereafter, among the members of the PJM Interconnection, L.L.C.

1.47 Operating Reserve shall mean the amount of generating capacity scheduled to be available for a specified period of an operating day to ensure the reliable operation of the PJM Region, as specified in the PJM Manuals.

1.48 Other Supplier shall mean a Member that is (i) a seller, buyer or transmitter of electric capacity or energy in, from or through the PJM Region, and (ii) is not a Generation Owner, Electric Distributor, Transmission Owner or End-Use Customer.

1.49 Partial Requirements Service shall mean wholesale service to supply a specified portion, but not all, of the power needs of a Load Serving Entity to serve end-users within the PJM Region that are not satisfied by its own generating facilities.

1.50 Party shall mean an entity bound by the terms of this Agreement.

1.51 PJM shall mean the PJM Board and the Office of the Interconnection.

1.52 PJM Board shall mean the Board of Managers of the PJM Interconnection, L.L.C., acting pursuant to the Operating Agreement.

1.53 PJM Manuals shall mean the instructions, rules, procedures and guidelines established by the Office of the Interconnection for the operation, planning and accounting requirements of the PJM Region.

1.54 PJM Open Access Transmission Tariff or **PJM Tariff** shall mean the tariff for transmission service within the PJM Region, as in effect from time to time, including any schedules, appendices, or exhibits attached thereto.

1.55 PJM Region shall have the same meaning as provided in the Operating Agreement.

1.56 PJM Region Installed Reserve Margin shall mean the percent installed reserve margin for the PJM Region required pursuant to this Agreement, as approved by the PJM Board pursuant to Schedule 4.1.

1.57 Planned Demand Resource shall mean a Demand Resource that does not currently have the capability to provide a reduction in demand or to otherwise control load, but that is scheduled to be capable of providing such reduction or control on or before the start of the Delivery Year for which such resource is to be committed, as determined in accordance with the requirements of Schedule 6.

1.58 Planned Generation Capacity Resource shall mean a Generation Capacity Resource participating in the generation interconnection process under part IV, subpart A of the PJM Tariff, for which Interconnection Service is scheduled to commence on or before the first day of the Delivery Year for which such resource is to be committed, for which a Facilities Study Agreement has been executed prior to its participation in the Base Residual Auction for such Delivery Year, and for which an Interconnection Service Agreement has been executed prior to its participation in any Incremental Auction for such Delivery Year. Notwithstanding the foregoing, for purposes of any Delivery Year for which the Base Residual Auction is conducted in calendar year 2006 as part of the Transition in implementing the Reliability Pricing Model, a Planned Generation Capacity Resource shall include a Generation Capacity Resource scheduled to be in service on or before the first day of such Delivery Year, for which a System Impact Study Agreement has been executed prior to its participation in the Base Residual Auction for such Delivery Year. A Generation Capacity Resource shall cease to be considered a Planned Generation Capacity Resource as of the date that Interconnection Service commences, in accordance with Part IV of the PJM Tariff, as to such resource

1.59 Planning Period shall mean the 12 months beginning June 1 and extending through May 31 of the following year, or such other period approved by the Members Committee.

1.60 Qualifying Transmission Upgrades shall have the meaning specified in Attachment Y to the PJM Tariff.

1.61 Reliability Committee shall mean the committee established pursuant to the Operating Agreement as a Standing Committee of the Members Committee.

1.62 Reliability Principles and Standards shall mean the principles and standards established by NERC or an Applicable Regional Reliability Council to define, among other things, an acceptable probability of loss of load due to inadequate generation or transmission capability, as amended from time to time.

1.63 Required Approvals shall mean all of the approvals required for this Agreement to be modified or to be terminated, in whole or in part, including the acceptance for filing by FERC and every other regulatory authority with jurisdiction over all or any part of this Agreement.

1.64 Season shall have the meaning provided in Attachment Y to the PJM Tariff

1.65 Self-Supply shall have the meaning provided in Attachment Y to the PJM Tariff.

1.66 South RAA shall mean that certain Reliability Assurance Agreement among Load-Serving Entities in the PJM South Region, on file with FERC as PJM Rate Schedule FERC No. 40.

1.67 State Consumer Advocate shall mean a legislatively created office from any State, all or any part of the territory of which is within the PJM Region, and the District of Columbia established, inter alia, for the purpose of representing the interests of energy consumers before the utility regulatory commissions of such states and the District of Columbia and the FERC.

1.68 Thirty-Minute-Start Resource shall mean a generation resource that has demonstrated thirty-minute-start capability in accordance with Schedule 9.1 of this Agreement.

1.69 Transmission Facilities shall mean facilities that: (i) are within the PJM Region; (ii) meet the definition of transmission facilities pursuant to FERC's Uniform System of Accounts or have been classified as transmission facilities in a ruling by FERC addressing such facilities; and (iii) have been demonstrated to the satisfaction of the Office of the Interconnection to be integrated with the PJM Region transmission system and integrated into the planning and operation of the PJM Region to serve all of the power and transmission customers within the PJM Region.

1.70 Transmission Owner shall mean a Member that owns or leases with rights equivalent to ownership Transmission Facilities. Taking transmission service shall not be sufficient to qualify a Member as a Transmission Owner.

1.71 **Transmission Owners Agreement** shall mean that certain agreement, dated June 2, 1997 and as amended from time to time, among transmission owners within the PJM Control Area.

1.72 **Unforced Capacity** shall mean installed capacity rated at summer conditions that is not on average experiencing a forced outage or forced derating, calculated for each Capacity Resource on the 12-month period from October to September without regard to the ownership of or the contractual rights to the capacity of the unit.

1.73 **West RAA** shall mean the "PJM West Reliability Assurance Agreement among the Load Serving Entities in the PJM West Region," on file with FERC as PJM Rate Schedule FERC No. 32.

1.74 **West Transmission Owner** shall mean a Member that has executed that certain "West Transmission Owners Agreement among PJM Interconnection, L.L.C. and Certain Owners of Electric Transmission Facilities," (PJM Interconnection L.L.C. Rate Schedule FERC No. 33).

1.75 **Zonal Capacity Price** shall mean the price of Unforced Capacity in a Zone that an LSE is obligated to pay for a Delivery Year as determined pursuant to Attachment Y to the PJM Tariff.

1.76 **Zone** shall mean an area within the PJM Region, as set forth in Schedule 15, or as such areas may be (i) combined as a result of mergers or acquisitions or (ii) added as a result of the expansion of the boundaries of the PJM Region.

ARTICLE 2 -- PURPOSE

This Agreement is intended to ensure that adequate Capacity Resources, including planned and existing Generation Capacity Resources, planned and existing Demand Resources, and ILR will be planned and made available to provide reliable service to loads within the PJM Region, to assist other Parties during Emergencies and to coordinate planning of such resources consistent with the Reliability Principles and Standards. Further, it is the intention and objective of the Parties to implement this Agreement in a manner consistent with the development of a robust competitive marketplace. To accomplish these objectives, this Agreement is among all of the Load Serving Entities within the PJM Region. Unless this Agreement is terminated as provided in Section 3.3, every entity which is or will become a Load Serving Entity within the PJM Region is to become and remain a Party to this Agreement or to an agreement (such as a requirements supply agreement) with a Party pursuant to which that Party has agreed to act as the agent for the Load Serving Entity for purposes of satisfying the obligations under this Agreement related to the load within the PJM Region of that Load Serving Entity. Nothing herein is intended to abridge, alter or otherwise affect the emergency powers the Office of the Interconnection may exercise under the Operating Agreement and PJM Tariff.

ARTICLE 3 -- TERM AND TERMINATION OF THE AGREEMENT

3.1 Term. This Agreement shall become effective as of June 1, 2006 and shall govern Unforced Capacity Obligations for the Planning Period beginning as of that date ("Initial Delivery Year"), and for each Planning Period thereafter, unless and until terminated in accordance with the terms hereof.

3.2 Transition Provisions. The East RAA, West RAA, and South RAA shall govern, in accordance with their terms now in effect or as hereafter validly amended, capacity requirements for each Planning Period through the end of the Planning Period ending May 31, 2006. Subject to the termination provisions in each such agreement, the East RAA, West RAA, and South RAA shall terminate effective 11:59:59 p.m. on May 31, 2006.

3.3 Termination.

3.3.1 Rights to Terminate. This Agreement may be terminated by a vote in the Members Committee to terminate the Agreement by an affirmative Sector Vote as specified in the Operating Agreement and upon the receipt of all Required Approvals related to the termination of this Agreement. Any such termination must be approved by the PJM Board and filed with the FERC and shall become effective only upon the FERC's approval.

3.3.2 Obligations upon Termination. Any provision of this Agreement that expressly or by implication comes into or remains in force following the termination of this Agreement shall survive such termination. The surviving provisions shall include, but shall not be limited to: (a) final settlement of the obligations of each Party under Articles 8 and 12 of this Agreement, including the accounting for the period ending with the last day of the month for which the Agreement is effective, (b) the provisions of this Agreement necessary to conduct final billings, collections and accounting with respect to all matters arising hereunder and (c) the indemnification provisions as applicable to periods prior to such termination.

ARTICLE 4 -- ADDITION OF NEW PARTIES

Each Party agrees that any entity that (i) is or will become a Load Serving Entity, (ii) complies with the process and data requirements set forth in Schedule 1, and (iii) meets the standards for interconnection set forth in Schedule 2 shall become a Party to this Agreement and shall be listed on Schedule 16 of this Agreement upon becoming a party to the Operating Agreement, and execution of a counterpart of this Agreement.

ARTICLE 5 -- WITHDRAWAL OR REMOVAL OF A PARTY

5.1 Withdrawal of a Party.

5.1.1 Notice. Upon written notice to the Office of the Interconnection, any Party may withdraw from this Agreement, effective upon the completion of its obligations hereunder and the documentation by such Party, to the satisfaction of the Office of the Interconnection, that such Party is no longer a Load Serving Entity.

5.1.2 Determination of Obligations. A Party's obligations hereunder shall be completed as of the end of the last month for which such Party's obligations have been set at the time said notice is received, except as provided in Article 13, or unless the Members Committee determines that the remaining Parties will be able to adjust their obligations and commitments related to the performance of this Agreement consistent with such earlier withdrawal date as may be requested by the withdrawing Party, without undue hardship or cost, while maintaining the reliability of the PJM Region.

5.1.3 Survival of Obligations upon Withdrawal. (a) The obligations of a Party upon its withdrawal from this Agreement and any obligations of that Party under this Agreement at the time of its withdrawal shall survive the withdrawal of the Party from this Agreement. Upon the withdrawal of a Party from this Agreement, final settlement of the obligations of such Party under Articles 7 and 11 of this Agreement shall include the accounting through the date established pursuant to Sections 5.1.1 and 5.1.2.

(b) Any Party that withdraws from this Agreement shall pay all costs and expenses associated with additions, deletions and modifications to communication, computer, and other affected facilities and procedures, including any filing fees, to effect the withdrawal of the Party from the Agreement.

(c) Prior to withdrawal, a withdrawing Party desiring to remain interconnected with the PJM Region shall enter into a control area to control area interconnection agreement with the Office of the Interconnection and the transmission owner or Electric Distributor within the PJM Region with which its facilities are interconnected.

5.1.4 Regulatory Review. Any withdrawal from this Agreement shall be filed with FERC and shall become effective only upon FERC's approval.

5.2 Breach by a Party. If a Party (a) fails to pay any amount due under this Agreement within 30 days after the due date or (b) is in breach of any material obligation under this Agreement, the Office of the Interconnection shall cause a notice of such non-payment or breach to be sent to that Party. If the Party fails, within 3 days of the receipt of such notice (except as otherwise described below), to cure such non-payment or breach, or if the breach cannot be cured within such time and if the Party does not diligently commence to cure the breach within such time and to diligently pursue such cure to completion, the Office of the Interconnection and the remaining Parties may, without an election of remedies, exercise all remedies available at law or in equity or other appropriate proceedings. Such proceedings may include (c) the commencement of a proceeding before the appropriate state regulatory commission(s) to request suspension or revocation of the breaching Party's license or authorization to serve retail load within the state(s) and/or (d) bringing any civil action or actions or recovery of damages that may include, but not be limited to, all amounts due and unpaid by the breaching Party, and all costs and expenses reasonably incurred in the exercise of its remedies hereunder (including, but not limited to, reasonable attorneys' fees).

ARTICLE 6 -- MANAGEMENT ADMINISTRATION

Except as otherwise provided herein, this Agreement shall be managed and administered by the Parties, Members, and State Consumer Advocates through the Members Committee and the Reliability Committee as a Standing Committee thereof, except as delegated to the Office of the Interconnection and except that only the PJM Board shall have the authority to approve and authorize the filing of amendments to this Agreement with the FERC.

ARTICLE 7 -- RESERVE REQUIREMENTS AND OBLIGATIONS

7.1 **Forecast Pool Requirement and Unforced Capacity Obligations.** (a) The Forecast Pool Requirement shall be established to ensure a sufficient amount of capacity to meet the forecast load plus reserves adequate to provide for the unavailability of Generation Capacity Resources, load forecasting uncertainty, and planned and maintenance outages. Schedule 4 sets forth guidelines with respect to the Forecast Pool Requirement.

(b) Unless the Party and its customer that is also a Load Serving Entity agree that such customer is to bear direct responsibility for the obligations set forth in this Agreement, (i) any Party that supplies Full Requirements Service to a Load Serving Entity within the PJM Region shall be responsible for all of that Load Serving Entity's capacity obligations under this Agreement for the period of such Full Requirements Service and (ii) any Party that supplies Partial Requirements Service to a Load Serving Entity within the PJM Region shall be responsible for such portion of the capacity obligations of that Load Serving Entity as agreed by the Party and the Load Serving Entity so long as the Load Serving Entity's full capacity obligation under this Agreement is allocated between or among Parties to this Agreement.

7.2 **Responsibility to Pay Locational Reliability Charge.** Each Party shall pay, as to the loads it serves in each Zone during a Season of a Delivery Year, a Locational Reliability Charge for each such Zone during such Season. The Locational Reliability Charge shall equal such Party's Daily Unforced Capacity Obligation in a Zone, as determined pursuant to Schedule 8 of this Agreement, times the Final Zonal Capacity Price for such Season for such Zone, as determined pursuant to Attachment Y of the PJM Tariff.

7.3 **LSE Option to Provide Capacity Resources.** A Party may partially or wholly offset amounts it must pay for the Locational Reliability Charge for a Delivery Year by offering Capacity Resources for sale in the Base Residual Auction or Second Incremental Auction, if such auction is held, applicable to such Delivery Year; provided such resources clear such auctions. Resources offered for sale in any such auction must satisfy the requirements specified in this Agreement and the PJM Manuals. A Party may choose to nominate a resource in the Base Residual Auction as Self-Supply, may choose to designate a price offer for such resource into any such auction, or may indicate in its offer that it wishes to commit such resource regardless of the clearing price, in which case the Party shall receive the marginal value of system capacity and the price adders for any applicable binding locational or operational constraint in accordance with Attachment Y of the PJM Tariff. Each Party acknowledges that the clearing price it receives for a resource offered for sale and cleared, or Self-Supplied, in an auction may differ from the Final Zonal Capacity Price determined for the applicable Zone for the applicable

Delivery Year, and that the Party shall remain responsible for the Locational Reliability Charge notwithstanding any such difference between the Capacity Resource Clearing Price and the Final Zonal Capacity Price. In addition, Parties recognize that they may receive an allocation of Capacity Transfer Rights which may offset a portion of the Locational Reliability Charge, and that they may offset a portion of the Locational Reliability Charge by nominating ILR, or by offering and clearing Qualifying Transmission Upgrades in the Base Residual Auction.

7.4 Capacity Plans and Deliverability. Each Party electing to provide Capacity Resources to meet its obligations hereunder shall submit to the Office of the Interconnection its plans (or revisions to previously submitted plans), as prescribed by Schedule 7, to install or contract for Capacity Resources. As set forth in Schedule 10, each Party must designate its Capacity Resources as Network Resources or Points of Receipt under the PJM Tariff to allow firm delivery of the output of its Capacity Resources to the Party's load within the PJM Region and each Party must obtain any necessary Firm Transmission Service in an amount sufficient to deliver Capacity Resources from outside the PJM Region to the border of the PJM Region to reliably serve the Party's load within the PJM Region.

7.5 Nature of Resources. Each Party electing to Self-Supply resources shall provide or arrange for specific, firm Capacity Resources that are capable of supplying the energy requirements of its own load on a firm basis without interruption for economic conditions and with such other characteristics that are necessary to support the reliable operation of the PJM Region, as set forth in more detail in Schedules 6, 9 and 10.

7.6 Compliance Audit of Parties. (a) For the 36 months following the end of each Planning Period, each Party shall make available the records and supporting information related to the performance of this Agreement from such Planning Period for audit.

(b) The Office of the Interconnection shall evaluate and determine the need for an audit of a Party and shall, upon a decision of the Members Committee to require such an audit, provide the Party or Parties to be audited with notice at least 90 days in advance of the audit.

(c) Any audit of a Party conducted pursuant to this Agreement shall be performed by an independent consultant to be selected by the Office of the Interconnection. Such audit shall include a review of the Party's compliance with the procedures and standards adopted pursuant to this Agreement.

(d) Prior to the completion of its audit, the independent consultant shall review its preliminary findings with the Party being audited and, upon the completion of its audit, the independent consultant shall issue a final audit report detailing the results of the audit, which final report shall be issued to the Party being audited, the Office of the Interconnection and the Reliability Committee; provided, however, no confidential data of any Party shall be disclosed through such audit reports.

(e) If, based on a final audit report, an adjustment is required to any amounts due to or from the Parties pursuant to Schedules 8, 12, or 13, such adjustment shall be accounted for in determining the amounts due to or from the Parties pursuant to Schedules 8, 12, or 13 for the month in which the adjustment is identified.

ARTICLE 8 -- DEFICIENCY, DATA SUBMISSION, AND EMERGENCY CHARGES

8.1 Nature of Charges. Upon the advice and recommendations of the Members Committee, the PJM Board shall, subject to any Required Approvals, approve certain charges to be imposed on a Party for its failure to satisfy its obligations under this Agreement, as set forth in Schedule 12.

8.2 Determination of Charge Amounts. No later than April 1 of each year, the Members Committee shall recommend to the PJM Board such charges to be applicable under this Agreement during the following Planning Period and Schedule 12, which, upon approval by the PJM Board, shall be modified accordingly, subject to the receipt of all Required Approvals. The Reliability Committee may establish projected charges for estimating purposes only.

8.3 Distribution of Charge Receipts. All of the monies received as a result of any charges imposed pursuant to this Agreement shall be disbursed as provided in this Agreement.

ARTICLE 9 -- COORDINATED PLANNING AND OPERATION

9.1 Overall Coordination. Each Party shall cooperate with the other Parties in the coordinated planning and operation of their owned or contracted for Capacity Resources to obtain a degree of reliability consistent with the Reliability Principles and Standards. In furtherance of such cooperation each Party shall:

(a) coordinate its Capacity Resource plans with the other Parties to maintain reliable service to its own electric customers and those of the other Parties;

(b) cooperate with the members and associate members of such Party's Applicable Regional Reliability Council to ensure the reliability of the region;

(c) make available its Capacity Resources to the other Parties through the Office of the Interconnection for coordinated operation and to supply the needs of the PJM Region for Operating Reserves;

(d) provide or arrange for Network Transmission Service or Firm Point-to-Point Transmission Service for service to the projected load of the Party and include all Capacity Resources as Network Resources designated pursuant to the PJM Tariff or Points of Receipt for Firm Point-to-Point Transmission Service;

(e) provide or arrange for sufficient reactive capability and voltage control facilities to meet Good Utility Practice and to be consistent with the Reliability Principles and Standards;

(f) implement emergency procedures and take such other coordination actions as may be necessary in accordance with the directions of the Office of the Interconnection in times of Emergencies; and

(g) maintain or arrange for Black Start Capability for a portion of its Capacity Resources at least equal to that established from time-to-time by the Office of the Interconnection.

9.2 Generator Planned Outage Scheduling. Each Party shall develop, or cause to be developed, its schedules of planned outages of its Capacity Resources. Such schedules of planned outages shall be submitted to the Office of the Interconnection for coordination with the schedules of planned outages of other Parties and anticipated transmission planned outages.

9.3 Data Submissions. Each Party shall submit to the Office of the Interconnection the data and other information necessary for the performance of this Agreement, including its plans for the addition, modification and removal of Capacity Resources, its load forecasts, and such other data set forth in Schedule 11.

9.4 Charges for Failures to Comply. (a) An emergency procedure charge, as set forth in Attachment Y to the PJM Tariff, shall be imposed on any Party that fails to comply with the directions of the Office of the Interconnection pursuant to Section 9.1(f)

(b) A data submission charge, as set forth in Schedule 12, shall be imposed on any Party that fails to submit the data, plans or other information required by this Agreement in a timely or accurate manner as provided in Schedule 11.

9.5 Metering. Each Party shall comply with the metering standards for the PJM Region, as set forth in the PJM Manuals.

ARTICLE 10 -- SHARED COSTS

10.1 Recording and Audit of Costs. (a) Any costs related to the performance of this Agreement, including the costs of the Office of the Interconnection and such other costs that the Members Committee determines are to be shared by the Parties, shall be documented and recorded in a manner acceptable to the Parties.

(b) The Members Committee may require an audit of such costs; provided, however, the cost records shall be available for audit by any Member or State Consumer Advocate, at the sole expense of such Member or State Consumer Advocate, for 36 months following the end of the Planning Period in which the costs were incurred.

10.2 Cost Responsibility. The costs determined under Section 10.1(a) shall be allocated to and recovered from the Parties to this Agreement and other entities pursuant to Schedule 9-5 of the PJM Tariff.

ARTICLE 11 -- BILLING AND PAYMENT

11.1 Periodic Billing. Each Party shall receive a statement periodically setting forth (i) any amounts due from or to that Party as a result of any charges imposed pursuant to this Agreement and (ii) that Party's share of any costs allocated to that Party pursuant to Article 10.

To the extent practical, such statements are to be coordinated with any billings or statements required pursuant to the Operating Agreement or PJM Tariff.

11.2 Payment. The payment terms and conditions shall be as set forth in the billing statement and shall, to the extent practicable, be the same as those then in effect under the PJM Tariff.

11.3 Failure to Pay. If any Party fails to pay its share of the costs allocated pursuant to Article 10, those unpaid costs shall be allocated to and paid by the other Parties hereto in proportion to the sum of the Daily Unforced Capacity Obligations of each such Party for the billing month. The Office of the Interconnection shall enforce collection of a Party's share of the costs.

ARTICLE 12 -- INDEMNIFICATION AND LIMITATION OF LIABILITIES

12.1 Indemnification. (a) Each Party agrees to indemnify and hold harmless each of the other Parties, its officers, directors, employees or agents (other than PJM Interconnection, L.L.C., its board or the Office of the Interconnection) for all actions, claims, demands, costs, damages and liabilities asserted by third parties against the Party seeking indemnification and arising out of or relating to acts or omissions in connection with this Agreement of the Party from which indemnification is sought, except (i) to the extent that such liabilities result from the willful misconduct of the Party seeking indemnification and (ii) that each Party shall be responsible for all claims of its own employees, agents and servants growing out of any workmen's compensation law. Nothing herein shall limit a Party's indemnity obligations under Article 16 of the Operating Agreement.

(b) The amount of any indemnity payment under this Section 12.1 shall be reduced (including, without limitation, retroactively) by any insurance proceeds or other amounts actually recovered by the Party seeking indemnification in respect of the indemnified actions, claims, demands, costs, damages or liabilities. If any Party shall have received an indemnity payment in respect of an indemnified action, claim, demand, cost, damage, or liability and shall subsequently actually receive insurance proceeds or other amounts in respect of such action, claim, demand, cost, damage, or liability, then such Party shall pay to the Party that made such indemnity payment the lesser of the amount of such insurance proceeds or other amounts actually received and retained or the net amount of the indemnity payments actually received previously.

12.2 Limitations on Liability. No Party will be liable to another Party for any claim for indirect, incidental, special or consequential damage or loss of the other Party including, but not limited to, loss of profits or revenues, cost of capital or financing, loss of goodwill and cost of replacement power arising from such Party's carrying out, or failure to carry out, any obligations contemplated by this Agreement; provided, however, nothing herein shall be deemed to reduce or limit the obligation of any Party with respect to the claims of persons or entities not a party to this Agreement.

12.3 Insurance. Each Party shall obtain and maintain in force such insurance as is required of Load Serving Entities by the states in which it is doing business within the PJM Region.

ARTICLE 13 -- SUCCESSORS AND ASSIGNS

13.1 Binding Rights and Obligations. The rights and obligations created by this Agreement and all Schedules and supplements thereto shall inure to and bind the successors and assigns of the Parties; provided, however, no Party may assign its rights or obligations under this Agreement without the written consent of the Members Committee unless the assignee concurrently becomes the Load Serving Entity with regard to the end-users previously served by the assignor.

13.2 Consequences of Assignment. Upon the assignment of all of its rights and obligations hereunder to a successor consistent with the provisions of Section 13.1, the assignor shall be deemed to have withdrawn from this Agreement.

ARTICLE 14 -- NOTICE

Except as otherwise expressly provided herein, any notice required hereunder shall be in writing and shall be sent: overnight courier, hand delivery, telecopy or other reliable electronic means to the representative on the Members Committee of such Party at the address for such Party previously provided by such Party to the other Parties. Any notice shall be deemed to have been given (i) upon delivery if given by overnight courier, hand delivery or certified mail or (ii) upon confirmation if given by facsimile or other reliable electronic means.

ARTICLE 15 -- REPRESENTATIONS AND WARRANTIES

15.1 Initial Representations and Warranties. Each Party represents and warrants to the other Parties that, as of the date it becomes a Party:

(a) the Party is duly organized, validly existing and in good standing under the laws of the jurisdiction where organized;

(b) the execution and delivery by the Party of this Agreement and the performance of its obligations hereunder have been duly and validly authorized by all requisite action on the part of the Party and do not conflict with any applicable law or with any other agreement binding upon the Party. The Agreement has been duly executed and delivered by the Party, and this Agreement constitutes the legal, valid and binding obligation of the Party enforceable against it in accordance with its terms except insofar as the enforceability thereof may be limited by applicable bankruptcy, insolvency, reorganization, fraudulent conveyance, moratorium or other similar laws affecting the enforcement of creditor's rights generally and by general principles of equity regardless of whether such principles are considered in a proceeding at law or in equity; and

(c) there are no actions at law, suits in equity, proceedings or claims pending or, to the knowledge of the Party, threatened against the Party before or by any federal, state, foreign or local court, tribunal or governmental agency or authority that might materially delay, prevent or hinder the performance by the Party of its obligations hereunder.

15.2 Continuing Representations and Warranties. Each Party represents and warrants to the other Parties that throughout the term of this Agreement:

(a) the Party is a Load Serving Entity;

(b) the Party satisfies the requirements of Schedule 2;

(c) the Party is in compliance with the Reliability Principles and Standards;

(d) the Party is a signatory, or its principals are signatories, to the agreements set forth in Schedule 3;

(e) the Party is in good standing in the jurisdiction where incorporated; and

(f) the Party will endeavor in good faith to obtain any corporate or regulatory authority necessary to allow the Party to fulfill its obligations hereunder.

ARTICLE 16 -- OTHER MATTERS

16.1 Relationship of the Parties. This Agreement shall not be interpreted or construed to create any association, joint venture, or partnership between or among the Parties or to impose any partnership obligation or partnership liability upon any Party.

16.2 Governing Law. This Agreement shall be interpreted, construed and governed by the laws of the State of Delaware.

16.3 Severability. Each provision of this Agreement shall be considered severable and if for any reason any provision is determined by a court or regulatory authority of competent jurisdiction to be invalid, void or unenforceable, the remaining provisions of this Agreement shall continue in full force and effect and shall in no way be affected, impaired or invalidated, and such invalid, void or unenforceable provision shall be replaced with valid and enforceable provision or provisions which otherwise give effect to the original intent of the invalid, void or unenforceable provision.

16.4 Amendment. This Agreement may be amended only by action of the PJM Board. Notwithstanding the foregoing, an Applicant eligible to become a Party in accordance with the procedures set forth in Article 4 shall become a Party by executing a counterpart of this Agreement without the need for execution of such counterpart by any other Party. The PJM Office of the Interconnection shall file with FERC any amendment to this Agreement approved by the PJM Board.

16.5 Headings. The article and section headings used in this Agreement are for convenience only and shall not affect the construction or interpretation of any of the provisions of this Agreement.

16.6 Confidentiality. (a) No Party shall have a right hereunder to receive or review any documents, data or other information of another Party, including documents, data or other information provided to the Office of the Interconnection, to the extent such documents, data or information have been designated as confidential pursuant to the procedures adopted by the Office of the Interconnection or to the extent that they have been designated as confidential by another Party; provided, however, a Party may receive and review any composite documents, data and other information that may be developed based on such confidential documents, data or information if the composite document does not disclose any individual Party's confidential data or information.

(b) Notwithstanding anything in this Section to the contrary, if a Party is required by applicable laws, or in the course of administrative or judicial proceedings, to disclose information that is otherwise required to be maintained in confidence pursuant to this Section, that Party may make disclosure of such information; provided, however, that as soon as the Party learns of the disclosure requirement and prior to making disclosure, that Party shall notify the affected Party or Parties of the requirement and the terms thereof and the affected Party or Parties may direct, at their sole discretion and cost, any challenge to or defense against the disclosure requirement and the Party shall cooperate with such affected Parties to the maximum extent practicable to minimize the disclosure of the information consistent with applicable law. Each Party shall cooperate with the affected Parties to obtain proprietary or confidential treatment of such information by the person to whom such information is disclosed prior to any such disclosure.

(c) Any contract with a contractor retained to provide technical support or to otherwise assist with the administration of this Agreement shall impose on that contractor a contractual duty of confidentiality that is consistent with this Section.

16.7 Counterparts. This Agreement may be executed in any number of counterparts, each of which shall be an original but all of which together will constitute one instrument, binding upon all parties hereto, notwithstanding that all of such parties may not have executed the same counterpart.

16.8 No Implied Waivers. The failure of a Party to insist upon or enforce strict performance of any of the provisions of this Agreement shall not be construed as a waiver or relinquishment to any extent of such Party's right to assert or rely upon any such provisions, rights and remedies in that or any other instance; rather, the same shall be and remain in full force and effect.

16.9 No Third Party Beneficiaries. This Agreement is intended to be solely for the benefit of the Parties and their respective successors and permitted assigns and is not intended to and shall not confer any rights or benefits on any third party not a signatory hereto.

16.10 Dispute Resolution. Except as otherwise specifically provided in the Operating Agreement, disputes arising under this Agreement shall be subject to the dispute resolution provisions of the Operating Agreement.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed by their duly authorized representatives.

[Signatures]

SCHEDULE 1

PROCEDURES TO BECOME A PARTY

A. Notice

Any entity that is or will become a Load Serving Entity within the PJM Region and thus a Party to the Reliability Assurance Agreement shall submit a notice to the Office of the Interconnection together with (i) its representation that it has satisfied or will (prior to the date the Reliability Assurance Agreement is to become effective as to that entity) satisfy the requirements to become a Party, (ii) all data required to coordinate planning and operations within the PJM Region as applicable, in a format defined in the PJM Manuals, and (iii) a deposit in an amount to be specified that will be applied toward the costs of the required analysis.

The required notice, representations, data and deposit must be submitted in sufficient time to conduct an analysis of the data submitted and to adjust the obligations of the Parties for the month in which the entity desires to become a Party:

- If the then existing boundaries of the PJM Region would be expanded by an entity becoming a Party, that entity shall submit the required notice, representation, data and deposit no later than when the entity applies for transmission service under the PJM Tariff.

- If an entity will serve load within the then existing boundaries of the PJM Region, that entity shall submit the required notice, representations, data and deposit as soon as possible prior to the month (i) in which it is to begin serving loads within the PJM Region or (ii) in which any agency relationship through which the entity's obligations under this Agreement had been satisfied is terminated; provided, however, that such submission shall not be required sooner than any request for transmission service or any change in the designation of Network Resources or points of receipt and loads under the PJM Tariff associated with providing service to those loads.

B. Analysis of Data

The notice, representations and data submitted to the Office of the Interconnection are to be analyzed in accordance with procedures consistent with this Agreement and the encouragement of reliable operation of the PJM Region.

C. Response

Upon completion of the analysis, the Office of the Interconnection will inform the entity of (a) the estimated costs and expenses associated with modifications to communication, computer and other facilities and procedures, including any filing fees, needed to include the entity as a Party, (b) the entity's share of any costs pursuant to Article 10, and (c) the earliest date upon which the entity could become a Party. In addition, a counterpart of the Agreement shall be forwarded for execution.

D. Agreement by New Party

After receipt of the response from the Office of the Interconnection, the entity shall identify its representative to the Members Committee and Reliability Committee and execute the counterpart of the Agreement, indicating the desired effective date; provided, however, such effective date shall be the first day of a month, may be no earlier than the date indicated in the response from the Office of the Interconnection and shall be no later than (i) the date on which the entity begins serving loads within the PJM Region or (ii) the termination date of any agency relationship through which its obligations under this Agreement had been satisfied. The executed counterpart of the Agreement, together with payment of its share of any costs then due, shall be returned as directed by the Office of the Interconnection.

SCHEDULE 2

STANDARDS FOR INTEGRATING AN ENTITY INTO THE PJM REGION

A. The following standards will be applied by the Office of the Interconnection to determine the eligibility of an entity to become a part of the PJM Region. For an entity to be integrated into the PJM Region it must possess generation and transmission attributes that would enable the entity to share its reserves with other entities in the PJM Region. Appropriate transmission and reliability studies are to be performed to determine the adequate transmission capability necessary to integrate the entity into the PJM Region consistent with Good Utility Practice.

B. In addition, the entity shall meet the following requirements to be included in the PJM Region:

1. All load, generation and transmission operating as part of the PJM Region's interconnected system must be included within the metered boundaries of the PJM Region.

2. The entity will accept and comply with the PJM Region's standards with respect to system design, equipment ratings, operating practices and maintenance practices as set forth in the PJM Manuals so that sufficient electrical equipment, control capability, information and communication are available to the Office of the Interconnection for planning and operation of the PJM Region.

3. The load, generation and transmission facilities of each entity shall be included in the telemetry to the Office of the Interconnection from a 24-hour control center. Each system operator in these control centers must be trained and delegated sufficient authority to take any action necessary to assure that the system for which the operator is responsible is operated in a stable and reliable manner.

4. Each entity must have compatible operational communication mechanisms, maintained at its expense, to interact with the Office of the Interconnection and for internal requirements.

5. Each entity must assure the continued compatibility of its local system energy management system monitoring and telecommunications systems to satisfy the technical requirements of interacting with the Office of the Interconnection as it directs the operation of the PJM Region.

SCHEDULE 3

OTHER AGREEMENTS TO BE EXECUTED BY THE PARTIES

- Any agreement for Network Transmission Service or Firm Point-To-Point Service that is required under the PJM Tariff for service consistent with the requirements of Section 9.1(d); and

- The Operating Agreement.

SCHEDULE 4

GUIDELINES FOR DETERMINING THE FORECAST POOL REQUIREMENT

A. Objective Of The Forecast Pool Requirement

The Forecast Pool Requirement shall be determined for the specified Planning Periods to establish the level of Capacity Resources that will provide an acceptable level of reliability consistent with the Reliability Principles and Standards.

B. Forecast Pool Requirement and PJM Region Installed Reserve Margin To Be Determined Annually

No later than one month in advance of each Base Residual Auction for a Delivery Year, based on the projections described in section C of this Schedule, and after consideration of the recommendation of the Members Committee, the PJM Board shall establish the Forecast Pool Requirement, including the PJM Region Installed Reserve Margin for the Parties for such Delivery Year. Unless otherwise agreed by the PJM Board, the Forecast Pool Requirement and PJM Region Installed Reserve Margin for such Planning Period shall be considered firm and not subject to re-determination thereafter.

C. Methodology

Each year, the Forecast Pool Requirement for at least each of the next five Planning Periods shall be projected by applying suitable probability methods to the data and forecasts provided by the Parties and obtained from Electric Distributors, as described in Schedule 11, the Operating Agreement and in the PJM Manuals. The projection of the Forecast Pool Requirement shall consider the following data and forecasts as necessary:

1. Seasonal peak load forecasts for each Planning Period as calculated by PJM in accordance with the PJM Manuals reflecting (a) load forecasts with a 50 percent probability of being too high or too low and (b) summer peak diversities determined by the Office of the Interconnection from recent experience.

2. Forecasts of aggregate seasonal load shape of the Parties which are consistent with forecast averages of 52 weekly peak loads prepared by the Parties and obtained from Electric Distributors for their respective systems.

3. Variability of loads within each week, due to weather and other recurring and random factors, as determined by the Office of the Interconnection.

4. Generating unit capability and types for every existing and proposed unit.

5. Generator Forced Outage rates for existing mature generating units, as determined by the Office of the Interconnection, based on data submitted by the Parties for their respective systems, from recent experience, and for immature and proposed

units based upon forecast rates related to unit types, capabilities and other pertinent characteristics.

6. Generator Maintenance Outage factors and planned outage schedules as determined by the Office of the Interconnection based on forecasts and historical data submitted by the Parties for their respective systems.

7. Miscellaneous adjustments to capacity due to all causes, as determined by the Office of the Interconnection, based on forecasts submitted by the Parties for their respective systems.

8. The emergency capacity assistance available as a function of interconnections of the PJM Region with other Control Areas, as limited by the capacity benefit margin considered in the determination of available transfer capability and the probable availability of generation in excess of load requirements in such areas.

D. Capacity Benefit Margin

The capacity benefit margin initially shall be 3,500 megawatts. Periodically, in consultation with the Members Committee, the Office of the Interconnection shall review and modify, if necessary, the capacity benefit margin to balance external emergency capacity assistance and internal installed capacity reserves so as to minimize the total cost of the capacity reserves of the Parties, consistent with the Reliability Principles and Standards. The Office of the Interconnection will reflect such modification prospectively in its development of the Forecast Pool Requirement for future Planning Periods.

SCHEDULE 4.1

DETERMINATION OF THE FORECAST POOL REQUIREMENT

A. Based on the guidelines set forth in Schedule 4, the Forecast Pool Requirement, in percent, shall be determined as set forth in this Schedule 4.1 on an unforced capacity basis.

$$FPR = (100 + IRM) * (1 - \text{average } EFOR_D/100)$$

where

average $EFOR_D$ = the average equivalent demand forced outage rate for the PJM Region, stated in percent and determined in accordance with Section B hereof

IRM – the PJM Region Installed Reserve Margin approved by the PJM Board for that Planning Period, stated in percent

B. The PJM Region equivalent demand forced outage rate ("average $EFOR_D$") shall be determined as the capacity weighted $EFOR_D$ for all units expected to serve loads within the PJM Region during the Delivery Year, as determined pursuant to Schedule 5.

SCHEDULE 5
FORCED OUTAGE RATE CALCULATION

A. The equivalent demand forced outage rate ("$EFOR_D$") shall be calculated as follows:

$$EFOR_D (\%) = \{(f_f * FOH + f_p * EFPOH) / (SH + f_f * FOH)\} * 100$$

where

f_f – full outage factor
f_p – partial outage factor
FOH – full forced outage hours
EFPOH – equivalent forced partial outage hours
SH – service hours

B. Calculation of $EFOR_D$ for individual Generation Capacity Resources.

For each Delivery Year, $EFOR_D$ shall be calculated at least one month prior to the start of the Third Incremental Auction for: (i) each Generation Capacity Resource for which a sell offer will be submitted in such Third Incremental Auction; and (ii) each Generation Capacity Resource previously committed to serve load in such Delivery Year pursuant to prior auctions for such Delivery Year. Such calculation shall be based upon such resource's service history in the twelve (12) consecutive months ending September 30 last preceding such auction. Historical data shall be based on official reports of the Parties under rules and practices set forth in the PJM Manuals. Such rate shall also include (i) an adjustment, if any, for capacity unavailable due to energy limitations determined in accordance with definitions and criteria set forth in the PJM Manuals and (ii) any other adjustments approved by the Members Committee to adjust the parameters of a designated unit.

1. The $EFOR_D$ of a unit in service twelve or more full calendar months prior to the calculation month shall be the average rate experienced by such unit during the twelve-month period specified above. Historical data shall be based on official reports of the Parties under rules and practices set forth in the PJM Manuals.

2. The $EFOR_D$ of a unit in service at least one full calendar month but less than the twelve-month period specified above shall be the average of the $EFOR_D$ experienced by the unit weighted by full months of service, and the class average rate for units with that capability and of that type weighted by a factor of [(twelve) minus (the number of months the unit was in service)]. Historical data shall be based on official reports of the Parties under rules and practices set forth in the PJM Manuals.

C. Calculation of average $EFOR_D$ for the PJM Region

The forecast average $EFOR_D$ for the PJM Region in a Delivery Year shall be the average of the forced outage rates, weighted for unit capability and expected time in service, attributable to all of the Generation Capacity Resources within the PJM Region, that are planned to be in service during the Delivery Year, including Generation Capacity Resources purchased from specified units and excluding Generation Capacity Resources sold outside the PJM Region from specified units. Such rate shall also include (i) an adjustment, if any, for capacity unavailable due to energy limitations determined in accordance with definitions and criteria set forth in the PJM Manuals and (ii) any other adjustments developed by the Office of Interconnection and maintained in the PJM Manuals to adjust the parameters of a designated unit when such parameters are or will be used to determine a future PJM Region reserve requirement and such adjustment is required to more accurately predict the future performance of such unit in light of extraordinary circumstances. For the purposes of this Schedule, the average $EFOR_D$ shall be the average of the capacity-weighted $EFOR_D$s of all units committed to serve load in the PJM Region. All rates shall be in percent.

1. The $EFOR_D$ of a unit not yet in service or which has been in service less than one full calendar year at the time of forecast shall be the class average rate for units with that capability and of that type, as estimated and used in the calculation of the Forecast Pool Requirement.

2. The $EFOR_D$ of a unit in service five or more full calendar years at the time of forecast shall be the average rate experienced by such unit during the five most recent calendar years. Historical data shall be based on official reports of the Parties under rules and practices developed by the Office of Interconnection and maintained in the PJM Manuals.

3. The EFORD of a unit in service at least one full calendar year but less than five full calendar years at the time of the forecast shall be determined as follows:

Full Calendar Years of Service	
1	One-fifth the rate experienced during the calendar year, plus four-fifths the class average rate.
2	Two-fifths the average rate experienced during the two calendar years, plus three-fifths the class average rate.
3	Three-fifths the average rate experienced during the three calendar years, plus two-fifths the class average rate.
4	Four-fifths the average rate experienced during the four calendar years, plus one-fifth the class average rate.

SCHEDULE 6

PROCEDURES FOR DEMAND RESOURCES AND ILR

A. Parties can partially or wholly offset the amounts payable for the Locational Reliability Charge with Demand Resources or ILR that are operated under the direction of the Office of the Interconnection. Demand Resources qualifying under the criteria set forth below may be offered for sale or designated as Self-Supply in the Base Residual Auction, or offered for sale in any Incremental Auction, for any Delivery Year for which such resource qualifies. In addition, resources qualifying under the criteria set forth below may be certified as ILR for a Delivery Year no later than three months prior to the first day of such Delivery Year. Qualified Demand Resources and ILR may be provided by a Demand Resource Provider or ILR Provider, notwithstanding that such provider is not a Party to this Agreement.

1. A Party must formally notify, in accordance with the requirements of the PJM Manuals and paragraph G of this schedule as applicable, the Office of the Interconnection of the Demand Resource or ILR that it is placing under the direction of the Office of the Interconnection.

2. A Party must agree to reserve, for interruption at the direction of the Office of the Interconnection, at least 10 interruptions per Planning Period.

3. The Demand Resource or ILR must be available during the summer period of June through September in the corresponding Delivery Year to be certified or to be offered for sale or Self-Supplied in an auction for the corresponding Delivery Year.

4. A period of no more than 2 hours prior notification must apply to interruptible customers.

5. The initiation of load interruption, upon the request of the Office of the Interconnection, must be within the authority of the dispatchers of the Party. No additional approvals should be required.

6. The initiation of load reduction upon the request of the Office of the Interconnection is considered an emergency action and must be implementable prior to a voltage reduction.

7. A Party must agree to reserve interruptions of at least 6-hour duration. As a minimum, such 6-hour duration for interruptions should be available on weekdays during the 8-hour daily peak window for the appropriate season. There will be no credit given to Parties who choose to provide interruption less than 6 hours and/or exclusive of the above time period.

8. An entity offering for sale, or designating for self-supply, any Planned Demand Resource must demonstrate, in accordance with standards and procedures set forth in the PJM Manuals, that such resource shall have the capability to provide a reduction in demand, or otherwise control load, on or before the start of the Delivery Year for which such resource is committed.

B. The Unforced Capacity value of a Demand Resource and ILR will be determined as:

the product of the Nominated Value of the Demand Resource, or the Nominated Value of the ILR, times the DR Factor, times the Forecast Pool Requirement. The DR Factor is a factor established by the PJM Board with the advice of the Members Committee to reflect the increase in the peak load carrying capability in the PJM Region due to Demand Resources and ILR for the PJM Region divided by the total Nominated Value of Demand Resources and ILR in the PJM Region. The DR Factor will be determined using an analytical program that uses a probabilistic approach to determine reliability. The determination of the DR Factor will consider the reliability of Demand Resources and ILR, the number of interruptions, and the total amount of load reduction. The detailed procedures used for calculating the DR Factor shall be set forth in the PJM Manuals.

C. Demand Resources offered and cleared in a Base Residual or Incremental Auction shall receive the corresponding Capacity Resource Clearing Price as determined in such auction, in accordance with Attachment Y of the PJM Tariff. Demand Resources are ineligible to receive any operational reliability constraint price adders.

D. Certified ILR resources shall receive the Adjusted Zonal Capacity Price, less any price adders for binding operational reliability constraints, in accordance with Attachment Y of the PJM Tariff.

E. The Party, Electric Distributor, Demand Resource Provider, or ILR Provider that establishes a contractual relationship (by contract or tariff rate) with a customer for load reductions is entitled to receive the compensation specified in sections C and D for a committed Demand Resource or certified ILR, notwithstanding that such provider is not the customer's energy supplier.

F. Any Party hereto shall demonstrate that its Demand Resources or ILR performed during periods when load management procedures were invoked by the Office of the Interconnection. The Office of the Interconnection shall adopt and maintain rules and procedures for verifying the performance of such resources. In addition, committed Demand Resources and certified ILR that do not comply with the directions of the Office of the Interconnection to reduce load during an emergency shall be subject to the penalty charge set forth in Attachment Y to the PJM Tariff.

G. Prior to the commencement of the Planning Period, Parties may elect to place Demand Resources associated with Behind The Meter Generation under the direction of the Office of the Interconnection. This election shall remain in effect for the entire Planning Period. In the event such an election is made, such Behind The Meter Generation will not be netted from load for the purposes of calculating the Daily Unforced Capacity Obligations under this Agreement.

SCHEDULE 7

PLANS TO MEET OBLIGATIONS

A. Each Party that elects to meet its estimated obligations for a Delivery Year by Self-Supply of Capacity Resources shall submit to the Office of the Interconnection, no later than one month prior to the start of the Base Residual Auction for such Delivery Year, its plans for such Capacity Resources, including (1) installation of Generation Capacity Resources (2) purchases, and (3) installation of Demand Resources or ILR.

B. The Capacity Resource plans of each Party shall indicate the nature and current status of each resource, including the status of a Planned Generation Capacity Resource or Planned Demand Resource, the potential for deactivation or retirement of a Generation Capacity Resource or Demand Resource, and the status of commitments for each sale or purchase of capacity included in its plans. The Office of the Interconnection will review the adequacy of the submittals hereunder both as to timing and content.

C. A Party that Self-Supplies Capacity Resources to satisfy its obligations for a Delivery Year must submit a Sell Offer as to such resource in the Base Residual Auction for such Delivery Year, in accordance with Attachment Y to the PJM Tariff.

D. If, at any time after the close of the Third Incremental Auction for a Delivery Year, including at any time during such Delivery Year, a Capacity Resource that a Party has committed as a Self-Supplied Capacity Resource becomes physically incapable of delivering capacity or reducing load, the Party may submit a replacement Capacity Resource to the Office of the Interconnection. Such replacement Capacity Resource (1) may not be previously committed for such Delivery Year, (2) shall be capable of providing the same quantity of megawatts of capacity or load reduction as the originally committed Capacity Resource, (3) shall be located in the same Locational Deliverability Area, if applicable, as the originally committed resource, and (4) shall, if applicable, be capable of satisfying Resource Operational Reliability Requirements to the same extent as the original committed Capacity Resource. In accordance with Attachment Y to the PJM Tariff, the Office of the Interconnection shall determine the acceptability of the replacement Capacity Resource.

SCHEDULE 8

DETERMINATION OF UNFORCED CAPACITY OBLIGATIONS

A. For each billing month during a Delivery Year, the Daily Unforced Capacity Obligation of a Party shall be determined on a daily basis for each Zone as follows:

Daily Unforced Capacity Obligation = OPL x Final Zonal RPM Scaling Factor x FPR/100

Where:

OPL – Obligation Peak Load, defined as the daily summation of the weather-adjusted coincident summer peak, last preceding the Delivery Year, of the end-users in such Zone (net of operating Behind The Meter Generation, but not to be less than zero) for which such Party was responsible on that billing day, as determined in accordance with the procedures set forth in the PJM Manuals

Final Zonal RPM Scaling Factor = the factor determined as set forth in sections B and C of this Schedule

FPR = the Forecast Pool Requirement

B. Following the Base Residual Auction for a Delivery Year, the Office of the Interconnection shall determine the Base Zonal RPM Scaling Factor and the Base Zonal Unforced Capacity Obligation for each Zone for such Delivery Year as follows:

Base Zonal Unforced Capacity Obligation = ZWNSP * Base Zonal RPM Scaling Factor * FPR

and

Base Zonal RPM Scaling Factor = ZPLDY/ZWNSP x [RUCO / (RPLDY x FPR)]

Where:

ZPLDY – Preliminary Zonal Peak Load Forecast for such Delivery Year

ZWNSP – Zonal Weather-Normalized Summer Peak for the summer season concluding five years prior to the commencement of such Delivery Year

RUCO - the Base RTO Unforced Capacity Obligation.

RPLDY - RTO Preliminary Peak Load Forecast for such Delivery Year.

For purposes of such determination, PJM shall determine the Preliminary RTO Peak Load Forecast, and the Preliminary Zonal Peak Load Forecasts for each Zone, in accordance with the PJM Manuals for each Delivery Year no later than one month prior to the Base Residual Auction for such Delivery Year. PJM shall determine the Final RTO and Zonal Peak Load Forecasts in accordance with the PJM Manuals for each Delivery Year no later than one month prior to the Second Incremental Auction for such Delivery Year; provided, however, that if the Second Incremental Auction is not conducted, the Preliminary RTO and Zonal Peak Load Forecasts for the Delivery Year shall be the Final RTO and Zonal Peak Load Forecasts, respectively, for such year. PJM shall determine the most recent Weather Normalized Summer Peak for each Zone no later than seven months prior to the start of the Delivery Year, and shall calculate the RTO Weather Normalized Summer Peak as the sum of the Weather Normalized Summer Peaks for all Zones.

C. The Final RTO Unforced Capacity Obligation for a Delivery Year shall be equal to the sum of (i) the unforced capacity obligations satisfied through the Base Residual Auction and the Second Incremental Auction, if held, and (ii) the Forecast RTO ILR Obligation for such Delivery Year, times the DR Factor, times the Forecast Pool Requirement. The Final Zonal Unforced Capacity Obligation shall be equal to the sum of (i) the Base Zonal Unforced Capacity Obligation, and (ii) the unforced capacity obligation satisfied in the Second Incremental Auction times (the increase in the Final Zonal Peak Load Forecast from the Preliminary Zonal Peak Load Forecast divided by the increase in the RTO Final Peak Load Forecast from the RTO Preliminary Peak Load Forecast). If a Second Incremental Auction is not conducted, the Final Zonal Unforced Capacity Obligation shall be equal to the Base Zonal Unforced Capacity Obligation. The Final Zonal RPM Scaling Factor shall be equal to the Final Zonal Unforced Capacity Obligation divided by the Zonal Weather Normalized Summer Peak for the summer concluding prior to the commencement of such Delivery Year.

D. 1. No later than five months prior to the start of each Delivery Year, the Electric Distributor for a Zone shall allocate the most recent Weather Normalized Summer Peak for such Zone to determine the Obligation Peak Load for each end-use customer within such Zone.

2. During the Delivery Year, no later than 36 hours prior to the start of each operating day, the Electric Distributor shall provide to PJM for each Party to this Agreement serving load in such Electric Distributor's Zone the Obligation Peak Load for all end-use customers served by such Party in such Zone. The daily Unforced Capacity Obligation of a Party for such Operating Day shall not be subject to change thereafter.

3. For purposes of such allocations, the daily sum of the Obligation Peak Loads of all Parties serving load in a Zone must equal the Zonal Obligation Peak Load for such Zone.

SCHEDULE 9

PROCEDURES FOR ESTABLISHING THE CAPABILITY OF GENERATION CAPACITY RESOURCES

A. Such rules and procedures as may be required to determine and demonstrate the capability of Generation Capacity Resources for the purposes of meeting a Load Serving Entity's obligations under the Agreement shall be developed by the Office of Interconnection and maintained in the PJM Manuals.

B. The rules and procedures for determining and demonstrating the capability of generating units to serve load in the PJM Region shall be consistent with achieving uniformity for planning, operating, accounting and reporting purposes.

C. The rules and procedures shall recognize the difference in types of generating units and the relative ability of units to maintain output at stated capability over a specified period of time. Factors affecting such ability include, but are not limited to, fuel availability, stream flow for hydro units, reservoir storage for hydro and pumped storage units, mechanical limitations, and system operating policies.

SCHEDULE 9.1

RESOURCE OPERATIONAL RELIABILITY REQUIREMENTS

The Final Zonal Capacity Price determined pursuant to Attachment Y to the PJM Tariff shall recognize and quantify the reliability value of certain operating characteristics of Generation Capacity Resources. To ensure that Generation Capacity Resources in the PJM Region have sufficient operational flexibility to maintain reliability, and that such reliability value is properly recognized and quantified, the Office of the Interconnection shall: (a) establish Resource Operational Reliability Requirements for each Planning Period; and (b) certify Generation Capacity Resources that meet such requirements.

The Office of Interconnection shall establish minimum Resource Operational Reliability Requirements for the PJM Region, in accordance with the PJM Manuals, and consistent with NERC and Applicable Regional Reliability Council standards and Good Utility Practice, for Load-Following Resources and Thirty-Minute-Start Resources.

The Load-Following Requirement shall quantify the minimum amount of megawatts that must be committed for the Delivery Year from Load-Following Resources that are capable of either dispatching within a given range at or above a minimum ramp rate, or cycling on- and off-line to respond to changes in system load as they occur. The Thirty-Minute-Start Requirement shall quantify the minimum amount of megawatts required from Thirty-Minute-Start Resources that must be committed for the Delivery Year. The Load-Following and Thirty-Minute-Start Requirements are PJM Region-wide requirements.

The Load Following Requirement shall be equal to the Weather Normalized Summer Peak forecast times the load-following factor as specified by the PJM Manuals, times the Forecast Pool Requirement. The Thirty-Minute-Start Requirement shall be defined as a percentage of the weather normalized forecast summer peak load for the Delivery Year, times one minus the average EFORd for the PJM Region, as specified in the PJM Manuals.

In accordance with procedures set forth in the PJM Manuals, the Office of the Interconnection shall certify Generation Capacity Resources electrically located in the PJM Region (a) having either a flexible start capability or a dispatchable capability that are qualified to contribute towards the Load Following Requirement; and (b) having a thirty (30) minutes or less start-time capability that are qualified to contribute towards the Thirty-Minute-Start Requirement. To qualify as a flexible-start resource, a unit must be capable of at least three starts per day, and the combination of its minimum down time and minimum run time must be no more than eight hours. To qualify as a dispatchable resource, a unit must have a range between its minimum and maximum output and must be able to ramp at an average rate of at least 1 MW/minute over the unit's dispatchable range. To qualify as a thirty-minute-start resource, a resource must have generating capability over and above the capability needed to meet day-to-day peak demand that can be converted fully into energy within thirty (30) minutes of a request from the Office of the Interconnection.

A unit that is committed in a Base Residual or Incremental Auction as a Thirty-Minute-Start Resource or Load-Following Resource shall be required to specify parameters in its offer data to the PJM Interchange Energy Market consistent with such status, as specified in the PJM Manuals, and shall be subject to monitoring and/or performance tests to ensure compliance with such requirements. A unit that fails to either specify or meet such parameters shall be subject to deficiency charges as set forth in Attachment Y to the PJM Tariff.

SCHEDULE 10

PROCEDURES FOR ESTABLISHING DELIVERABILITY OF GENERATION CAPACITY RESOURCES

Generation Capacity Resources must be deliverable, consistent with a loss of load expectation as specified by the Reliability Principles and Standards, to the total system load, including portion(s) of the system in the PJM Region that may have a capacity deficiency at any time. Deliverability shall be demonstrated by either obtaining or providing for Network Transmission Service or Firm Point-To-Point Transmission Service within the PJM Region such that each Generation Capacity Resource is either a Network Resource or a Point of Receipt, respectively. In addition, for Generation Capacity Resources located outside the metered boundaries of the PJM Region that are used to meet an Unforced Capacity Obligation, the capacity and energy of such Generation Capacity Resources must be delivered to the metered boundaries of the PJM Region through firm transmission service.

Certification of deliverability means that the physical capability of the transmission network has been tested by the Office of the Interconnection and found to provide that service consistent with the assessment of available transfer capability as set forth in the PJM Tariff and, for Generation Resources owned or contracted for by a Load Serving Entity, that the Load Serving Entity has obtained or provided for Network Transmission Service or Firm Point-to-Point Transmission Service to have capacity delivered on a firm basis under specified terms and conditions.

SCHEDULE 10.1

LOCATIONAL DELIVERABILITY REQUIREMENTS

The Final Zonal Capacity Price determined pursuant to Attachment Y to the PJM Tariff shall recognize and quantify the locational value of Capacity Resources. To ensure that such locational value is properly recognized and quantified, the Office of the Interconnection shall follow the procedures in this Schedule.

A. To recognize and quantify the locational value of capacity, the Unforced Capacity Obligation shall include Locational Deliverability Requirements. In accordance with Attachment Y to the Tariff, the Office of the Interconnection shall determine and post, three months prior to the Base Residual Auction for each Delivery Year, the Locational Deliverability Areas applicable to such Delivery Year. Locational Deliverability Areas shall be those areas, identified by the load deliverability analyses conducted pursuant to the Regional Transmission Expansion Planning Protocol and the PJM Manuals that have a limited ability to import capacity due to physical limitations of the transmission system, voltage limitations or stability limitations. Such limits on import capability shall not reflect the effect of Qualifying Transmission Upgrades offered in the Base Residual Auction for Locational Deliverability Areas identified for a Delivery Year shall be modeled in the Base Residual Auction and any Incremental Auction conducted for such Delivery Year.

B. For each Locational Deliverability Area, the Office of the Interconnection shall determine, pursuant to procedures set forth in the PJM Manuals, an Internal Capacity Requirement, equal to the quantity, in megawatts, of Unforced Capacity that must by committed from Capacity Resources physically located in such Locational Deliverability Area.

SCHEDULE 11

DATA SUBMITTALS

To perform the studies required to determine the Forecast Pool Requirement and Daily Unforced Capacity Obligations under this Agreement and to determine compliance with the obligations imposed by this Agreement, each Party and other owner of a Capacity Resource shall submit data to the Office of the Interconnection in conformance with the following minimum requirements:

1. All data submitted shall satisfy the requirements, as they may change from time to time, of any procedures adopted by the Members Committee.

2. Data shall be submitted in an electronic format, or as otherwise specified by the Reliability Committee and approved by the PJM Board.

3. Actual outage data for each month for Generator Forced Outages, Generator Maintenance Outages and Generator Planned Outages shall be submitted so that it is received by such date specified in the PJM Manuals.

4. On or before the date specified in the PJM Manuals, planned and maintenance outage data for all Generation Resources and load forecasts (including seasonal and average weekly peaks) shall be submitted.

5. On or before the date specified in the PJM Manuals, adjustments to forecasts shall be submitted.

6. On or before the date or schedule for updates specified in the PJM Manuals, revisions to capacity and load forecasts (including the plans for satisfying the Daily Unforced Capacity Obligation of the Party) shall be submitted.

7. Capacity plans or revisions to previously submitted capacity plans, required under Schedule 6.

8. As desired by a Party, revisions to monthly peak load forecasts may be submitted.

The Parties acknowledge that additional information required to determine the Forecast Pool Requirement is to be obtained by the Office of the Interconnection from Electric Distributors in accordance with the provisions of the Operating Agreement.

SCHEDULE 12

DATA SUBMISSION CHARGES

A. Data Submission Charge

For each working day of delay in the submittal of information required to be submitted under this Agreement, a data submission charge of $500 shall be imposed.

B. Distribution Of Data Submission Charge Receipts

1. Each Party that has satisfied its obligations for data submittals pursuant to Schedule 11 during a Delivery Year, without incurring a data submission charge related to that obligation, shall share in any data submission charges paid by any other Party that has failed to satisfy said obligation during such Planning Period. Such shares shall be in proportion to the sum of the Unforced Capacity Obligations of each such Party entitled to share in the data submission charges for the most recent month.

2. In the event all of the Parties have incurred a data submission charge during a Delivery Year, those data submission charges shall be distributed as approved by the PJM Board.

SCHEDULE 13

EMERGENCY PROCEDURE CHARGES

Following an Emergency, the compliance of each Party with the instructions of the Office of the Interconnection shall be evaluated as directed by the Reliability Committee. If, based on such evaluation, it is determined that a Party refused to comply with, or otherwise failed to employ its best efforts to comply with, the instructions of the Office of the Interconnection to implement PJM emergency procedures, that Party shall pay an emergency procedure charge, as set forth in Attachment Y to the PJM Tariff. The revenue associated with Emergency Procedure Charges shall be allocated in accordance with Attachment Y to the PJM Tariff.

SCHEDULE 14

DELEGATION TO THE OFFICE OF THE INTERCONNECTION

The following responsibilities shall be delegated by the Parties to the Office of the Interconnection:

1. **New Parties.** With regard to the addition, withdrawal or removal of a Party:

   (a) Receive and evaluate the information submitted by entities that plan to serve loads within the PJM Region, including entities whose participation in the Agreement will expand the boundaries of the PJM Region. Such evaluation shall be conducted in accordance with the requirements of the Agreement.

   (b) Evaluate the effects of the withdrawal or removal of a Party from this Agreement.

2. Implementation of Reliability Assurance Agreement. With regard to the implementation of the provisions of this Agreement:

   (a) Receive all required data and forecasts from the Parties and other owners of Capacity Resources;

   (b) Perform all calculations and analyses necessary to determine the Forecast Pool Requirement and the obligations imposed under the Reliability Assurance Agreement, including periodic reviews of the capacity benefit margin for consistency with the Reliability Principles and Standards;

   (c) Monitor the compliance of each Party with its obligations under the Agreement;

   (d) Keep cost records, and bill and collect any costs or charges due from the Parties and distribute those charges in accordance with the terms of the Agreement;

   (e) Assist with the development of rules and procedures for determining and demonstrating the capability of Capacity Resources;

   (f) Establish the capability and deliverability of Generation Capacity Resources consistent with the requirements of the Reliability Assurance Agreement;

   (g) Establish standards and procedures for Planned Demand Resources;

   (h) Collect and maintain generator availability data;

(i) Perform any other forecasts, studies or analyses required to administer the Agreement;

(j) Coordinate maintenance schedules for generation resources operated as part of the PJM Region;

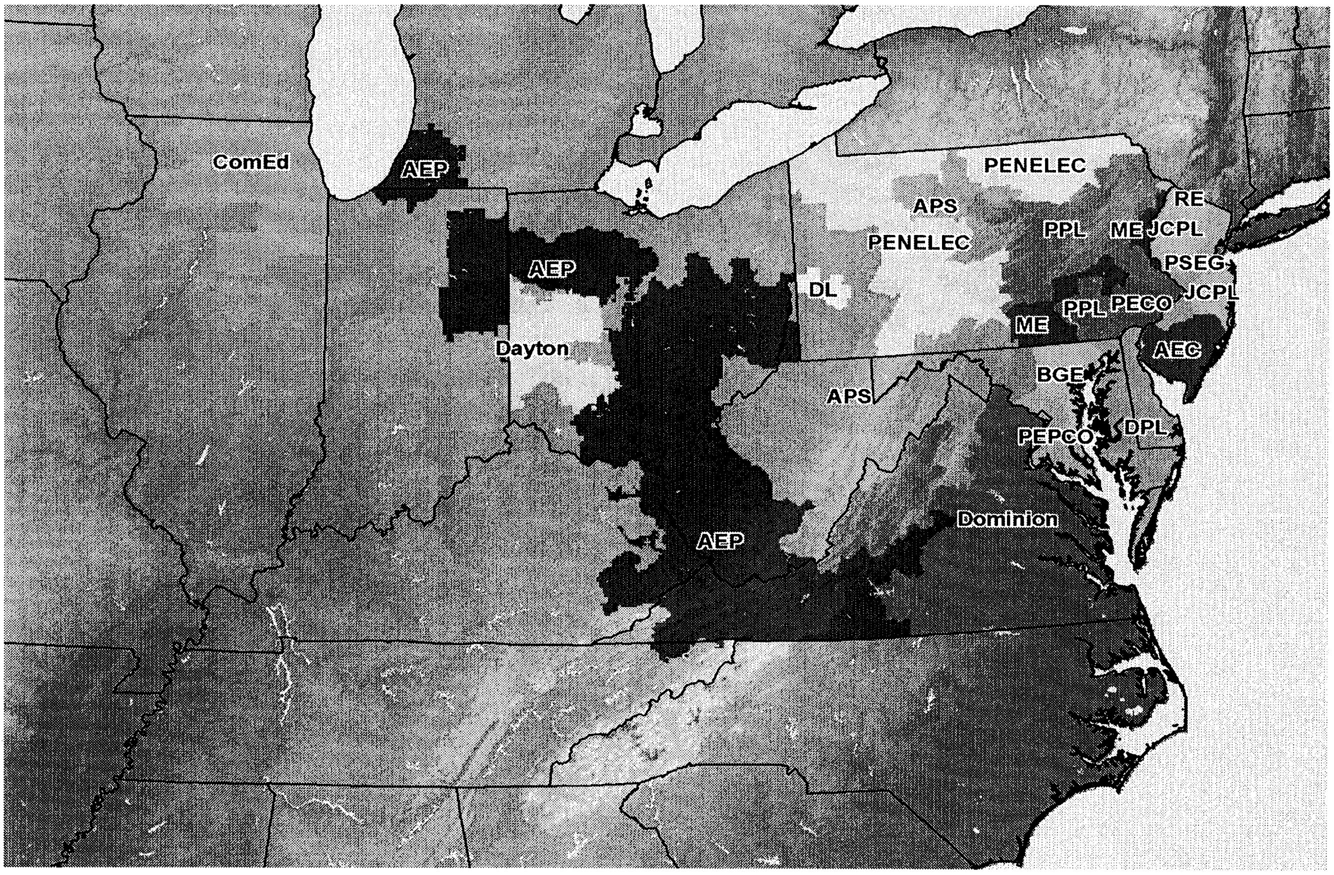
(k) Determine and declare that an Emergency exists or ceases to exist in all or any part of the PJM Region or announce that an Emergency exists or ceases to exist in a Control Area interconnected with the PJM Region;

(l) Enter into agreements for (i) the transfer of energy in Emergencies in the PJM Region or in a Control Area interconnected with the PJM Region and (ii) mutual support in such Emergencies with other Control Areas interconnected with the PJM Region; and

(m) Coordinate the curtailment or shedding of load, or other measures appropriate to alleviate an Emergency, to preserve reliability in accordance with FERC, NERC or Applicable Regional Reliability Council principles, guidelines, standards and requirements, and to ensure the operation of the PJM Region in accordance with Good Utility Practice.

SCHEDULE 15

ZONES WITHIN THE PJM REGION



FULL NAME	SHORT NAME
Pennsylvania Electric Company	PENELEC
Allegheny Power	APS
PPL Electric Utilities Corporation	PPL
Metropolitan Edison Company	ME
Jersey Central Power and Light Company	JCPL
Public Service Electric and Gas Company	PSEG
Atlantic City Electric Company	AEC
PECO Energy Company	PECO
Baltimore Gas and Electric Company	BGE
Delmarva Power and Light Company	DPL
Potomac Electric Power Company	PEPCO
Rockland Electric Company	RE
Commonwealth Edison Company	ComEd
AEP East Zone	AEP
The Dayton Power and Light Company	Dayton
Virginia Electric and Power Company	Dominion
Duquesne Light Company	DL

SCHEDULE 16

PARTIES TO THE RELIABILITY ASSURANCE AGREEMENT

This Schedule sets forth the Parties to the Agreement:

ACN Energy, Inc.
AES Power Direct, L.L.C.
Agway Energy Services-PA Inc.
Allegheny Energy Supply Company, L.L.C.
AllEnergy Marketing Company, L.L.C.
Amerada Hess Corporation
American Cooperative Services, Inc.
American Energy Solutions, Inc.
Atlantic City Electric Company
Baltimore Gas and Electric Company
BGE Home Products & Services, Inc.
BP Energy Company
Central Hudson Enterprise Corporation
CMS Marketing Services and Trading Company
Columbia Energy Power Marketing Corporation
Commodore Gas and Electric, Inc.
Commonwealth Energy Corporation dba electricAMERICA
Con Edison Energy, Inc.
Conectiv Energy Supply, Inc.
Constellation Energy Source, Inc.
Consolidated Edison Solutions, Inc.
Delmarva Power & Light Company
Dominion Retail, Inc.
DTE Edison America, Inc.
DTE Energy Market, Inc.
DTE Energy Trading, Inc.
Duke Energy Trading and Marketing, L.L.C.
DukeSolutions, Inc.
Easten Power Distribution Company
ECONnergy Energy Company, Inc.
ECONnergy PA, Inc.
Edison Mission Marketing & Trading, Inc.
Energy America, L.L.C.
Energy East Solutions, Inc.
Enron Energy Services, Inc.
Enron Power Marketing, Inc.
Exelon Energy Company

FirstEnergy Corporation
FirstEnergy Trading and Power Marketing Incorporated
FirstEnergy Services Corp.
GPU Advanced Resources
GreenMountain.com Company
HIS Power & Water, L.L.C.
It's Electric & Gas, L.L.C.
Jersey Central Power & Light Company
Keyspan Energy Services, Inc.
Metropolitan Edison Company
MIECO, Inc.
NewEnergy, Inc.
Niagara Mohawk Energy Marketing, Inc.
NJR Natural Energy Company
NRG New Jersey Energy Sales, L.L.C.
NYSEG Solutions, Inc.
Old Dominion Electric Cooperative
PECO Energy Company
Penn Power Energy, Inc.
Pennsylvania Electric Company
Pepco Energy Services, Inc.
Potomac Electric Power Company
PPL Electric Utilities Corporation
PPL EnergyPlus, L.L.C.
PSEG Energy Resources & Trade, L.L.C
PSEG Energy Technologies, Inc.
Public Service Electric and Gas Company
Reliant Energy Retail, Inc.
Rhoads Energy Corporation
Select Energy, Inc.
Sempra Energy Solutions
Sempra Energy Trading Corp.
Shell Energy Services Company, L.L.C.
Southern Company Retail Energy Marketing L.P.
South Jersey Energy Company
South Jersey Energy Solutions, L.L.C.
Smart Energy.com, Inc.
Statoil Energy Services, Inc.
Strategic Energy Ltd.
The Mack Services Group
The New Power Company
Total Gas & Electric, Inc.
Total Gas & Electricity (PA), Inc.
TXU Energy Trading Company d/b/a TXU Energy Services

UGI Energy Services, Inc.
UGI Utilities, Inc. - Electric Division
Utilimax.com, Inc.
Utility.com
Washington Gas Energy Services, Inc.
Williams Energy Market & Trading Company
Woodruff Energy
Worley & Obetz, Inc. d/b/a Advanced Energy

Harrison REA Inc.
City of New Martinsville
City of Philippi
Letterkenny Industrial Development Authority-PA
Old Dominion Electric Cooperative
Town of Front Royal
Hagerstown
Borough of Chambersburg
Town of Williamsport
Thurmont
Allegheny Electric Cooperative, Inc.
Allegheny Power
AES New Energy, Inc.

Commonwealth Edison Company
Commonwealth Edison Company of Indiana
Dayton Power & Light Company (The)
American Municipal Power-Ohio, Inc.
American Electric Power Service Corporation on behalf of its affiliates:
- Appalachian Power Company
- Columbus Southern Power Company
- Indiana Michigan Power Company
- Kentucky Power Company
- Kingsport Power Company
- Ohio Power Company
- Wheeling Power Company

Blue Ridge Power Agency, Inc.
Central Virginia Electric Cooperative
City of Dowogiac
Hoosier Energy REC, Inc.
Indiana Municipal Power Agency
Ormet Primary Aluminum Corporation
City of Sturgis
Wabash Valley Power Association, Inc.
Virginia Electric Power Company