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NEW JERSEY BOARD OF PUBLIC UTILITIES

BOARD STAFF REPORT
ON
NEW JERSEY CAPACITY, TRANSMISSION PLANNING AND INTERCONNECTION ISSUES

Docket Nos. EO11050309 and EO09110920

DIVISION OF ECONOMIC DEVELOPMENT and ENERGY POLICY

DECEMBER 2011

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I. EXECUTIVE SUMMARY

This report ("Capacity Report" or "Report") provides the Board Staff's recommendations on the issues concerning capacity, transmission planning and interconnection process based upon facts presented during: (i) the New Jersey Board of Public Utilities ("Board" or "BPU") investigation, which began in 2010; (ii) the Long-Term Capacity Agreement Pilot Program ("LCAPP") process; and (iii) the federal and regional proceedings connected to the LCAPP process.

First, the Capacity Report provides an introduction to the capacity issues New Jersey and the PJM Interconnection, L.L.C. ("PJM") are encountering. Second, the Report provides the procedural background on these issues at the federal, regional and state level. Third, the Report addresses the issues raised at the federal and regional level, and provides recommendations to the Board on potential strategies in its future relations with the Federal Energy Regulatory Commission ("FERC" or "Commission"), PJM and state and federal courts. Lastly, the Report addresses possible barriers to new entry within New Jersey and provides recommendations to the Board that may require legislative action and those that are fully within the jurisdictional reach of the Board.

II. INTRODUCTION

New Jersey faces intractable obstacles in the development of adequate electric resources to meet the needs of its residents and businesses. The transmission constraints limiting the ability to import power into the State are a longstanding problem whose solution involves the uncertain strategy of higher voltage reinforcement of the interstate transmission lines. The delay of the Susquehanna-Roseland line, due to the National Park Service's review of its impacts on the Delaware Water Gap National Recreation Area and surrounding federal land, illustrate the intrinsic difficulties in relying upon transmission upgrades as a near-term solution to New Jersey's resource adequacy needs. In the absence of interstate transmission sufficient to render a fluid west-to-east power market and the unpredictable state of its future of such transmission, New Jersey has been left with little choice but to rely on in-state generation capacity resources and a market construct ostensibly designed to incentivize resource development in the presence of such scarcity. New Jersey's reliance on the Reliability Pricing Model ("RPM") capacity market, however, has been a disappointing experience which can impact the state's economic health and its prospects for recovery from a severe and lengthy recession.

Since its implementation in 2007, RPM's annual capacity auctions have brought to New Jersey consumers high capacity prices - reflecting local generation shortages - but have produced little new generation capacity in response to those high market price signals. Rather, RPM has largely served as a new and lucrative source of revenue for incumbent generators who, in Staff's opinion have deferred the retirements of old, inefficient generation plants, reactivated previously deactivated facilities, or made comparatively modest investments to upgrade the capacity ratings of existing generating stations. The following table depicts cumulative capacity additions by type and relevant region from the initial 2007 implementation of RPM through the most recent auction, held in May 2011.

Table 1 - RPM New Capacity Resources (MW): 2007 through 2014/2015 Delivery Year[1]

Change in Capacity Availability (MW)	RTO	MAAC[2]	EMAAC	New Jersey
New Generation	7,477	3,023	2,143	**535**
Generation Upgrades	5,149	1,534	1,144	666
Generation Reactivations	539	379	198	194
Withdrawn or Canceled Retirements	3,715	3,415	2,327	**2,223**
Demand and Energy Efficiency Resources	16,287	8,343	3,378	1,947
Net Increase in Capacity Imports	9,006	-	-	-
Total Impact on Capacity Availability in 2014/2015 Delivery Year	42,173	16,694	9,190	5,565

The paucity of New Jersey-based new generation capacity and the exaggerated capacity "additions" associated with deferred plant retirements comes into relief when the relative distribution of in-state resources by type is compared with the results from other Locational Deliverability Areas ("LDAs") and the PJM-wide Regional Transmission Organization ("RTO"). Table 2 depicts the relative shares of resources by type acquired through RPM to date.

Table 2 - RPM New Capacity Resources (%): 2007 through 2014/2015 Delivery Year

Change in Capacity Availability (%)	RTO	MAAC	EMAAC	New Jersey
New Generation	18%	18%	23%	**10%**
Generation Upgrades	12%	9%	12%	12%
Generation Reactivations	1%	2%	2%	3%
Withdrawn or Canceled Retirements	9%	20%	25%	**40%**
Demand and Energy Efficiency Resources	39%	50%	37%	35%
Net Increase in Capacity Imports	21%	-	-	-
Total Impact on Capacity Availability in 2014/2015 Delivery Year	100%	100%	100%	100%

The data indicate that when compared to the experience of both the RTO as a whole and to LDAs to the west, New Jersey has experienced the least development of new generation capacity and the largest share of deferred retirement capacity. The development of actual new generation capacity resources serving New Jersey loads has

[1] Comments of PJM Interconnection, L.L.C., *IN THE MATTER OF THE BOARD'S INVESTIGATION OF CAPACITY PROCUREMENT AND TRANSMISSION PLANNING*, Docket No. EO11050309 (June 17, 2011) at 13 (hereafter "PJM Comments, June 17, 2011"). Depicted incremental capacity data for LDAs is cumulative: RTO includes the Mid- Atlantic Area Council ("MAAC"); MAAC includes the Eastern Mid-Atlantic Area Council ("EMAAC"); and EMAAC includes New Jersey additions.

been scant. Table 1, above, indicates that 535 megawatts of new generation capacity will be built in New Jersey by the 2014/2015 delivery year, representing a mere 10 percent of all "new capacity resources" developed in the state under RPM, and just seven percent of all new generation capacity built in PJM under RPM. New generation capacity in all of EMAAC, including the New Jersey zones, will account for less than 30 percent of all new generation capacity built in PJM through the 2014/2015 delivery year. Investment in new baseload and intermediate generation capacity that would serve to ensure long-term resource adequacy, greater fuel efficiency and lower energy and capacity prices to New Jersey consumers has remained conspicuously absent among PJM's pronounced successes of RPM. This is despite the fact that 2010 net revenues generated from the PJM energy, capacity and ancillary services markets in the New Jersey zones were sufficient to recover the levelized fixed costs of a new combined cycle unit, with 2011 on track to realize similar results.[3] Across the PJM footprint, new combined cycle capacity will account for only seven percent of all new capacity resources and only 29 percent of all incremental generation plant capacity by 2014/2015.[4]

Instead of incentivizing new and efficient resources, RPM has predominantly incentivized the prolonged service of old, inefficient resources that should have been retired. Owners of this generation reap the gratuitous benefits of a capacity market that provides a newfound revenue stream that rewards inefficient production merely because it is capable of serving as capacity for reliability purposes.[5] Incumbent generators with plants scheduled for retirement have withdrawn or cancelled those retirements, with the units accounting for a full 40 percent of so-called "new capacity resources" garnered by New Jersey through RPM. The otherwise retired units are anything but new resources; an examination of PJM's listing of qualifying capacity resources for the 2014/2015 delivery year reveals a large number of New Jersey-based simple cycle combustion turbines with vintages dating to the late 1960s and early 1970s.[6] EMAAC, which includes all New Jersey zones plus PECO in eastern Pennsylvania and Delmarva Power and Light on the Delmarva Peninsula, accounted for 63 percent of all deferred retirement

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3 www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2010/2010-som-pjm-volume2.pdf. 2010 State of the Market Report for PJM, Monitoring Analytics, L.L.C., Independent Market Monitor for PJM (March 10, 2011) at 181, Table 3-24 (hereafter referred to as the "2010 SOM") and www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2011.shtml 2011 Q3 State of the Market Report for PJM, Monitoring Analytics, L.L.C., Independent Market Monitor for PJM (November 14, 2011) at 67, Table 3-19 (hereafter referred to as the "2011 Q3 SOM").

4 http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/20110513-2014-15-base-residual-auction-report.ashx at Tables 7 and 9.

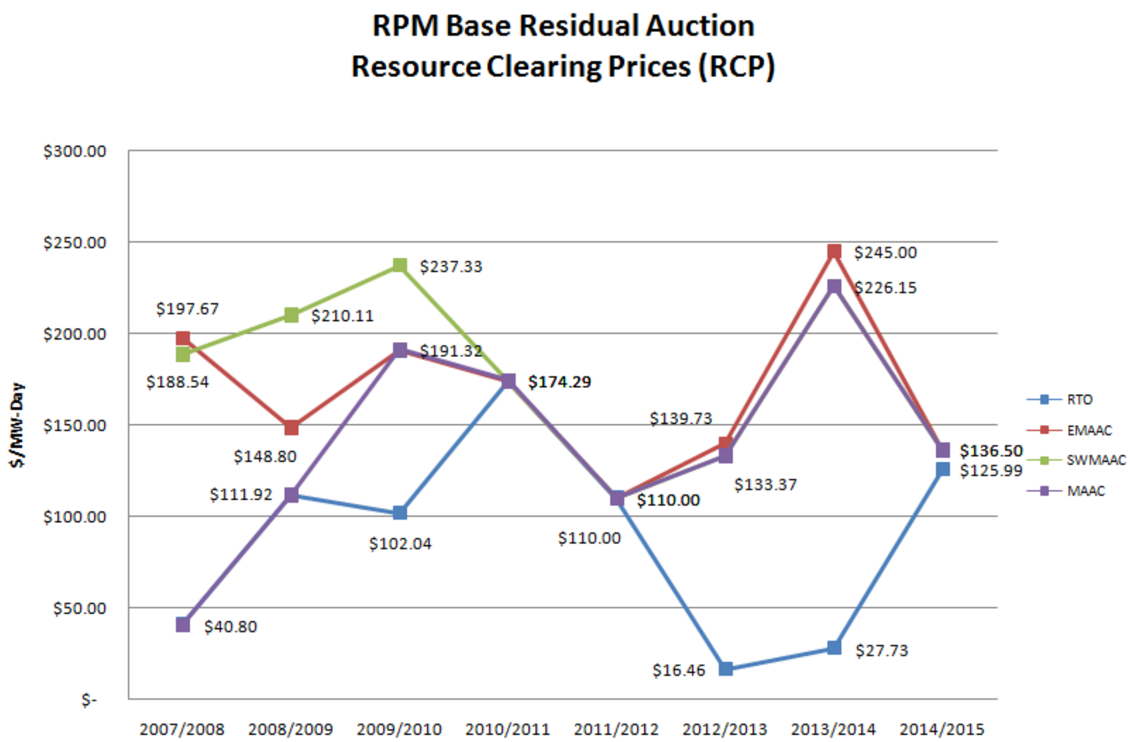
5 High Electric Demand Day ("HEDD") units in New Jersey are limited to the number of hours they can operate due to excessive emissions of nitrogen oxides ("NOx"). Despite their relative unavailability to generate energy when needed, HEDD units remain a substantial capacity asset in NJ's reliability portfolio. The Independent Market Monitor for PJM has recommended that HEDD units no longer be considered as capacity resources because their run limitations on peak demand days render them unable to meet their capacity resource obligations. See, Comments of the Market Monitor, IN THE MATTER OF THE BOARD'S INVESTIGATION OF CAPACITY PROCUREMENT AND TRANSMISSION PLANNING, Docket No. EO11050309 (October 14, 2011) at 5 (hereafter "IMM Comments, October 14, 2011").

6 http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/2014-2015-rpm-resource-model.ashx

"new capacity resources" in PJM to date under RPM. PJM lauds this deferral of otherwise retired generation capacity, characterizing it as a "valuable reliability benefit of RPM" accruing to New Jersey.[7] In addition to deferred retirement capacity, generation upgrades and reactivations account for another 15 percent of the claimed new capacity in New Jersey. While the upgrade of an existing unit with investment in new equipment does represent an incremental capacity resource, the reactivation of a previously deactivated unit is not the kind of promised *new* capacity envisioned with RPM's implementation.

These results are particularly disappointing for New Jersey consumers because they come in the midst of annual RPM clearing prices that are consistently among the highest in PJM. The three LDAs serving the state's loads that are routinely modeled by PJM prior to the annual RPM Base Residual Auctions ("BRA") - PS-NORTH, PSEG and EMAAC - represent geographic regions characterized by transmission constraints that are often *binding*, an electrical state that prevents the import of additional capacity into the area. When transmission constraints are binding, the resource clearing price of the LDA rises to signal the value of resource scarcity within the LDA. In this situation, the resource clearing price for the constrained LDA *separates* from the adjacent LDAs, with a higher price emerging as the incentive for generators to site new plant within the constrained LDA. Consistent LDA separation and attendant higher resource clearing prices should, over the course of time, bring the needed new capacity development to the particular LDA. Historic RPM resource clearing prices from the annual BRAs are depicted for the largest LDAs and the RTO in the following PJM-produced graph.

[7] PJM Comments, June 17, 2011 at 13-14.



Under the theory of locational capacity markets, New Jersey should have witnessed a vigorous development of new generation capacity in response to a heightened capacity resource price signal. In the last BRA, conducted in May 2011 for the 2014/2015 delivery year, EMAAC cleared at a price of $136.50/MW-day compared to the $125.99 price of the unconstrained RTO. Not depicted above is the $225/MW-day price for capacity clearing in PS-NORTH, a price nearly 80 percent above the RTO price. In the prior two BRAs, the price differentials between the RTO and the LDAs serving New Jersey were characterized not merely by multiples but by an order of magnitude: for the 2013/14 delivery year, EMAAC cleared at $245 compared to the RTO price of $27.73; and for the 2012/2013 delivery year, the RTO price was $16.46, while EMAAC cleared at $139.73 and PS-NORTH cleared at $185/MW-day. With the exception of the 2010/2011 and the 2011/2012 delivery years, the resource clearing prices for EMAAC and NJ-based LDAs have consistently and substantially exceeded that of the RTO. Since the 2009/2010 delivery year the MAAC LDA, which includes EMAAC and zones in northeastern Pennsylvania, has roughly tracked the high prices clearing in EMAAC; despite these high prices relative to the rest of the RTO, MAAC has seen just 40 percent of the new generation capacity accounted for in PJM since RPM's 2007 implementation.

By the conclusion of the 2014/2015 delivery year, New Jersey consumers will have paid an astounding $11.3 billion in RPM capacity payments, an annual average cost to the state exceeding $1.4 billion. Table 3, below, details the history of the annual and cumulative costs of those charges.

Table 3: RPM's Cost to New Jersey Electric Consumers[8]

Delivery Year	Zone	Zonal Price ($/MW-Day)	Zonal CTR Credit ($/MW-Day)	Net Load Price ($/MW-day)	UCAP (MW) Obligation	Annual Charges
2007/2008	AECO	$197.16	$20.16	$177.00	2,970.7	$192,448,287
	JCPL	$197.16	$20.16	$177.00	6,857.8	$444,254,118
	PSEG	$197.16	$20.16	$177.00	11,761.3	$761,909,723
	RECO	$197.16	$20.16	$177.00	454.6	$29,446,907
2008/2009	AECO	$150.53	$5.29	$145.24	2,982.0	$158,088,114
	JCPL	$150.53	$5.29	$145.24	6,872.2	$364,322,968
	PSEG	$150.53	$5.29	$145.24	11,727.8	$621,737,427
	RECO	$150.53	$5.29	$145.24	450.5	$23,883,816
2009/2010	AECO	$196.53	$2.83	$193.70	2,993.9	$211,667,858
	JCPL	$196.53	$2.74	$193.79	7,121.5	$503,717,488
	PSEG	$196.53	$2.70	$193.83	12,245.7	$866,343,535
	RECO	$196.53	$2.62	$193.91	481.2	$34,057,117
2010/2011	AECO	$182.85	$0.00	$182.85	3,013.5	$201,126,238
	JCPL	$182.85	$0.00	$182.85	7,182.2	$479,352,428
	PSEG	$182.85	$0.00	$182.85	12,226.7	$816,030,828
	RECO	$182.85	$0.00	$182.85	478.1	$31,911,285
2011/2012	AECO	$116.16	$0.00	$116.16	2,998.3	$127,465,110
	JCPL	$116.16	$0.00	$116.16	7,248.0	$308,132,575
	PSEG	$116.16	$0.00	$116.16	12,332.8	$524,302,772
	RECO	$116.16	$0.00	$116.16	482.4	$20,509,961
2012/2013	AECO	$145.79	$4.79	$141.00	3,024.9	$155,679,297
	JCPL	$145.79	$4.79	$141.00	7,172.9	$369,157,521
	PSEG	$169.80	$14.33	$155.47	12,087.7	$685,916,676
	RECO	$145.79	$4.79	$141.00	480.4	$24,721,821
2013/2014	AECO	$247.78	$2.45	$245.32	3,098.0	$277,407,538
	JCPL	$247.78	$2.45	$245.32	7,330.3	$656,378,360
	PSEG	$247.78	$2.45	$245.32	12,255.0	$1,097,352,206
	RECO	$247.78	$2.45	$245.32	486.9	$43,596,389
2014/2015	AECO	$135.25	$0.00	$135.25	3,105.6	$153,317,433
	JCPL	$135.25	$0.00	$135.25	7,323.4	$361,537,214
	PSEG	$179.81	$15.81	$164.00	12,208.7	$730,814,623
	RECO	$135.25	$0.00	$135.25	484.9	$23,940,299
Total						$11,300,527,930
Annual Average						$1,412,565,991

[8] http://www.pjm.com/markets-and-operations/rpm/rpm-auction-user-info.aspx#Item08 The 2012/2013, 2013/2014 and 2014/2015 Net Load Prices and MW Obligations are not yet finalized.

New generation capacity is evidently not responding to the heightened locational price signals emanating from successive RPM auctions; rather, the bulk of new generation capacity has been built in the lower priced areas of PJM. An explanation for this paradoxical outcome was one of the specific questions listed in the Board's notice for its second legislative-type hearing in this matter conducted on October 14, 2011 ("October Hearing").[9] In its filed comments in response to this query, PJM refutes the Board's observations, arguing that over the course of the last three BRAs – covering the delivery years 2012/2013, 2013/2014 and 2014/2015 - New Jersey ranked second among the PJM states in incremental generation capacity *offered* into the BRAs with 779.6 MW bid into RPM over that period.

From the data made available by PJM, it is unclear how much of the *offered* 779.6 MW was new plant capacity, upgrades or deferred retirements. What is extremely clear from the data is that very little, if any, of the New Jersey-based capacity actually *cleared* the BRAs; in fact, of the 695 MW of new EMAAC generation capacity offered for the 2014/2015 delivery year, only 74.2 MW *cleared* the auction, while for the 2013/2014 delivery year 110.3 MW cleared.[10] Published RPM results for the 2012/2013 delivery year do not detail how much new plant capacity located in New Jersey or EMAAC cleared the BRA, if any.[11] PJM points to "market dynamics" for the failure of New Jersey-based new capacity to clear the subject three BRAs, implying that the offer prices from these units were too high to be captured by the clearing prices.[12] Notwithstanding PJM's protestations to the contrary, the empirical evidence to date, compiled in Tables 1 and 2, above, testify to the fact that relative to the lower-priced areas of PJM, the LDAs directly serving New Jersey consumers have not seen the amount of new generation capacity development that should be indicated by the consistently higher level of market prices.

Identifiable near term future capacity development in the New Jersey area is equally disappointing. Capacity additions in either *active* or *under-construction* status in the PJM queue through September 2011 are disproportionately located in the western LDAs, west of New Jersey and EMAAC. Of the total of 86,864 MW of active or under-construction capacity projects in the queue across PJM, only 18,183 MW, representing 21 percent of the total, are located in EMAAC.[13] The New Jersey zones account for a mere 16 percent – 13,901 MW - of total active or under-construction capacity in the queue, with New Jersey based combined cycle capacity – 6,593 MW - representing less than half of that amount and less than eight percent of all capacity in the queue across

[9] http://www.bpu.state.nj.us/bpu/pdf/announcements/cpp1.pdf at question #5.

[10] http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/20110513-2014-15-base-residual-auction-report.ashx at Table 6B and http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/2013-2014-base-residual-auction-report.ashx at Table 6B.

[11] http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/2012-13-base-residual-auction-report-document-pdf.ashx

[12] PJM Comments, June 17, 2011 at 17-18

[13] *2011 Q3 SOM* at 73, Table 3-29.

the entire RTO.[14] Thus, 79 percent of new capacity in the PJM queue is being added outside of EMAAC and 84 percent of new capacity is slated for addition outside of New Jersey.

PJM points to the achievement of reliability under RPM as evidence of its success, but New Jersey electric consumers and the BPU were promised more when RPM was introduced in 2007. Simply put, beyond the evident objective of increased reliability was the promise that new market entry would drive a state of healthy competition and in turn prices to the state's consumers would fall over time. This anticipated state of the market has not materialized. Notwithstanding the impressive development of demand response and energy efficiency as capacity resources, new generation capacity development - in particular baseload and mid-merit capacity - has lagged. RPM instead appears to have simply enriched incumbent generation and imposed substantial new costs on New Jersey consumers for existing capacity, some of which is well beyond its normal service life. Unlike normal transactions between buyers and sellers in other markets, the RPM market has charged New Jersey customers handsomely for goods that it has not delivered.

The reasons for RPM's disappointing results to date in this regard may be found in several critical areas: fundamental design aspects of the RPM construct may impede rather than facilitate long-term capacity development, entrenched structural market power is likely impeding new entry and maintaining high prices, and a Byzantine PJM interconnection process, which could be subjected to the unmonitored exercise of market power, places potential new generation in a perpetual state of uncertainty in terms of the timing and cost of interconnection.

The RPM design provides for a single year capacity commitment with delivery three years into the future. The three-year forward auction structure was designed to allow new entrant capacity to compete with existing capacity resources, but this design appears to be falling well short of its objective. In particular, longer lead-time baseload and mid-merit generation likely require a more definitive revenue stream over a period exceeding a single year in order to secure external financing for these more capital intensive plants. While it is the case that baseload and mid-merit generating stations are designed to run at higher capacity factors than simple cycle combustion turbines, and therefore anticipate recovering a greater share of their revenue from the energy market than a peaking facility could expect to realize, capacity market revenue remains a critical component of the net revenue necessary to recover the fixed costs of these units. Providing a more predictable stream of capacity revenue over a longer time horizon than the single year effected under RPM may be required to spur sustained development of these types of new generation capacity resources. Efforts to address this need, discussed at greater length in other sections of this Capacity Report, have taken a number of forms.

Beyond RPM design issues, structural market power within the capacity market serves to ensure the continued dominance of incumbent generators and stifle new market entry. In its *2010 State of the Market Report for PJM*, the Independent Market Monitor for PJM ("IMM") re-iterated conclusions on structural market power that have become an annual boilerplate synopsis of the RPM market structure:

[14] *Ibid.* at Table 3-28.

> In other words, the market design for capacity leads, almost unavoidably, to structural market power. Given the basic features of market structure in the PJM Capacity Market, including significant market structure issues, inelastic demand, tight supply-demand conditions, the relatively small number of nonaffiliated LSEs and supplier knowledge of aggregate market demand, *the MMU concludes that the potential for the exercise of market power continues to be high. Market power is and will remain endemic to the existing structure of the PJM Capacity Market*. This is not surprising in that the Capacity Market is the result of a regulatory/administrative decision to require a specified level of reliability and the related decision to require all load serving entities to purchase a share of the capacity required to provide that reliability. It is important to keep these basic facts in mind when designing and evaluating capacity markets. The Capacity Market is unlikely ever to approach the economist's view of a competitive market structure in the absence of a substantial and unlikely structural change that results in much more diversity of ownership.[15]

Market power metrics employed by the IMM to measure market concentration reveal the capacity markets serving New Jersey to be the most highly concentrated in PJM. In its most recent annual Preliminary Market Structure Screen ("PMSS") conducted in advance of the May 2011 BRA for the 2014/2015 delivery year, the IMM calculated a Herfindahl-Hirschman Index ("HHI") value of 1966 for EMAAC, indicating a highly concentrated market.[16] EMAAC failed the more indicative Three Pivotal Supplier ("TPS") market power test, with a single generation owner possessing a 33.1 percent market share.[17] The PSEG LDA indicated an HHI of 8027 and a single pivotal supplier with an 89.4 percent market share; PS-North exhibited an HHI of 7825 with a single pivotal supplier holding an 88.2 percent market share.[18] EMAAC, PSEG and PS-North failed the Three Pivotal Supplier tests as did all other LDAs in PJM, with a single pivotal supplier

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[15] *2010 SOM* at 361. (*Emphasis supplied*).

[16] www.monitoringanalytics.com/reports/Reports/2011/PMSS_Results_20142015_20110201.pdf at 2. Hereafter referred to as the "2014/2015 PMSS." HHI is calculated as the sum of the squares of market share of each generation owner; an HHI value exceeding 1800 indicates a highly concentrated market. Market share exceeding 20 percent is also indicative of potential for market power abuse. (See, *2010 SOM* at 38.)

[17] *Ibid.* According to the IMM, the TPS test is more indicative of structural market power than are the HHI or market share metrics. The TPS test measures the relative importance of individual suppliers in meeting demand in a given market at a particular point in time. The TPS employs the Residual Supplier Index ("RSI"), a calculation that takes the total supply in the market less the supply of the individual generator(s), divided by the total demand of the market. An RSI of less than or equal to 1.0 indicates a pivotal supplier condition in that the supply of the individual generator, or generators, is necessary to meet market demand. A RSI exceeding 1.0 indicates that a generator, or group of generators, have a reduced ability to unilaterally influence market price. (See, *2010 SOM* at 38, 371.)

[18] *2011 Q3 SOM* at 136.

identified in every LDA.[19] In short, analysis under three separate measures of structural market power indicate that the New Jersey area LDAs exhibit extremely high levels of market concentration, with a single dominant generator in a position to exercise market power. In fact, all LDAs and the RTO itself failed the TPS test prior to the BRA for the 2014/2015 delivery year, requiring the application of offer caps to all price offers that could have affected the clearing price.[20] Indeed, only through the assiduous monitoring and offer price mitigation conducted by the IMM can the PJM capacity market be arguably construed as workably competitive.

While an array of rules exist governing the monitoring and mitigation of market power abuse in the *operation* of PJM markets, there are no discrete rules in place to prohibit the exercise of market power to *prevent new entry* into the markets. Dominant generators are in a position to exercise market power in ways that can effectively obstruct the development of new generation capacity in markets serving New Jersey consumers. Some of this behavior can be addressed through changes to current PJM practices while other behavior is rooted in advantages that exist as a legacy of the vertically integrated utility systems that preceded the deregulation of wholesale electricity generation. The exercise of market power to prevent new entry is evident in two discernible areas: the transmission interconnection process and in the availability of land to site new generation in proximity of existing transmission interconnection points.

Current PJM procedures governing the transmission interconnection review process provide that the transmission owners conduct the engineering studies used to identify upgrades necessary to assure system reliability and to quantify the costs associated with such upgrades. Transmission owning entities in PJM are frequently the subsidiaries of holding companies that also own generation affiliates actively participating in PJM markets; some of these generation affiliates are dominant market participants with market power. It is clearly not in the interest of such generation owning affiliates to see merchant capacity developed in markets where they are dominant suppliers; control over the interconnection study by their transmission affiliates thus provides a means to exercise anti-competitive control over the viability of the merchant project. Indeed, this inherent conflict may deter other generators from even considering building within such areas. Because the identification of necessary transmission upgrades does by definition entail a degree of subjective engineering latitude, transmission owners could specify a defensible scope of required upgrades and attendant costs that render prohibitive the economics of the merchant project. Unnecessarily rigorous review of merchant projects by transmission affiliates, while arguably checked by PJM's final review of the interconnection studies, undermines a process that should be empirical and somewhat flexible. The current transmission interconnection review process is impeded by this evident internal conflict of interest.

This potential for market power abuse by transmission owners for the benefit of their generation affiliates compounds an already problematic transmission interconnection

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[19] *Ibid*. The *2011 Q3 SOM* does not depict explicit RSI quantifications for the PSEG or EMAAC LDAs, but rather quantifies a unified RSI for MAAC/ SWMAAC/ EMAAC/ PSEG/DPL South/PEPCO, reflecting how the BRA actually cleared. The *2011 Q3 SOM* provides a discrete RSI of 0.0 for the PS-NORTH LDA, which separated and cleared with a discrete price. Based on data depicted for prior years for the PSEG and EMAAC LDAs, a Three Pivotal Supplier test RSI result of 0.0 can be assumed for the May 2011BRA.

[20] www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2011/2011q2-som-pjm-sec5.pdf *2011 Q2 SOM*, dated August 15, 2011, at 119. Hereafter referred to as the "*2011 Q2 SOM*."

queue process that serves as a barrier to new market entry. At present, merchant generation projects enter a transmission queue behind other projects based upon the date of the interconnection request to PJM, not on the actual viability of the project and potential in-service date. This standard for placement in the queue invites less than viable projects to request interconnection simply to reserve a preferred placement in the queue. Transmission interconnection studies for the merchant project are subject to the vagaries in the development status of all projects in the queue in front of them; that is, every time a project further up in the queue changes its interconnection status, all projects behind it are subject to revisions to their own interconnection studies. Such a process is a prescription for an ever-changing estimation of required transmission system upgrades and costs. Because merchant projects frequently rely upon external financing, the inherent uncertainty and delay of the process is often sufficient to cause project cancellation. For active capacity projects in the queue as of September 2011, the average time between entering the queue and the in-service date was 812 days with a standard deviation of 656 days, evidencing a lengthy in-queue average time with great variability around the average.[21] Of the 335,311 MW of capacity in queue from 1998 through January 2012, 218,358 MW – 65 percent - has been withdrawn.[22] The difficulty of developing merchant plant capacity under these circumstances was the subject of testimony before the Board in this proceeding. When the element of market power abuse, exercised through a transmission affiliate, is added to this Byzantine queue process, a potentially determinative impediment to new market entry emerges.

Incumbent generators and Electric Distribution Companies (“EDCs”) are also in a position to impede new entry through the ownership of land suitable for generation development. As a legacy of the days of vertically integrated utilities, generation subsidiaries and their affiliated EDCs have possession of the most suitable locations for generation plant transferred as part of the restructuring of the industry, whether this land currently has active generation sited on it or not, or it has remained with the utility and has continued to be held for future use. Located at prime transmission interconnection points, these sites often house some of the oldest peaking units still in service in the region, many well past their normal retirement age. Development of these sites with newer, more efficient and larger capacity units would not serve the economic interests of their owners since entities with market power benefit by maintaining supply shortage in the market. Control of infra-marginal capacity provides the incentive for market power abuse while control over marginal peaking units, however old and inefficient, provides the means to exercise that market power. Dominant incumbents in the markets serving New Jersey own generation capacity portfolios with precisely these attributes along the supply curve, making the control of ownership over available land for plant development a key ingredient to maintaining market power. It is simply not in the interest of incumbents or the affiliated EDCs to sell their property to competing merchant entities interested in securing available sites for generation plant development.

III. PROCEDURAL HISTORY

[21] *2011 Q3 SOM* at 73, Table 3-27.

[22] *Ibid.* at 72, Table 3-26.

A. THE STATE PROCESS

As part of the Basic Generation Service ("BGS") proceeding for the period beginning June 1, 2010, under Docket No. EO09050351, LS Power Associates, L.P. ("LS Power") requested that the Board establish a third BGS competitive process utilizing longer term contracts of 15 years. LS Power indicated that the new process would competitively bid for new, efficient, in-state generation of 100 MW or larger, which, according to LS Power, would enhance the reliability of the State's power supply. LS Power further recommended that the BPU order a stakeholder process to be convened to address the details of implementing this additional competitive process. By Order dated December 10, 2009, ("December Order") the Board denied LS Power's request that a third BGS competitive process be created. However, the Board determined that the issues raised by LS Power were part of the larger comprehensive energy policy for the State to ensure that there is enough generation to meet the electric power needs of New Jersey going forward. The Board directed Board staff ("Staff") to develop a process to review the State's power and capacity needs.

Pursuant to the December Order, Staff initiated a separate proceeding under Docket No. EO09110920[23]. On June 24, 2010, the Board held a technical conference ("Board Technical Conference") to discuss the challenges raised during the 2010 BGS proceeding regarding additional electric generation and capacity needs of New Jersey. By Notice dated June 25, 2010, the Board's Secretary requested that public comments under Docket No. EO09050351 be submitted by July 2, 2010. The following entities/persons submitted written comments at or subsequent to the Board Technical Conference: New Jersey Division of Rate Counsel ("Rate Counsel"), William H. Hogan, Ph.D, Competitive Power Ventures, Inc. ("CPV"), American Public Power Association ("APPA"), the four New Jersey EDCs[24], LS Power, and jointly the New Jersey Highlands Coalition, Sierra Club, and Stop the Lines! These comments are posted on the Board's website[25].

On January 28, 2011, Governor Chris Christie signed into law L. 2011, c. 9, amending and supplementing L. 1999, c. 23 ("LCAPP Law")[26], establishing the LCAPP to promote the construction of base load and mid-merit electric generation facilities for the benefit of New Jersey's electric consumers.

[23] In the Matter of the New Jersey Board of Public Utilities Review of the State's Electric Power and Capacity Needs -Docket No. EO09110920

[24] Public Service Electric and Gas Company ("PSE&G"), Jersey Central Power and Light Company ("JCP&L"), Rockland Electric Company ("Rockland"), Atlantic City Electric Company ("ACE").

[25] See: http://www.nj.gov/bpu/about/divisions/energy/capacity.html

[26] The LCAPP Law has been codified in the following sections of the New Jersey Statutes: N.J.S.A. 48:3-51, 48:3-60.1, 48:3-98.3-98.4.

On February 10, 2011, the Board issued an Order ("February Order") under Docket No. EO11010026: (i) initiating a proceeding to implement the actions required by the LCAPP Law, (ii) establishing a schedule, (iii) designating President Solomon as presiding officer on this matter, and (iv) selecting Levitan & Associates, Inc. ("LAI" or LCAPP "Agent") as the LCAPP Agent.

From March 11, 2011 to March 17, 2011, the Board held four public hearings throughout the State, one in each EDC's service territory, allowing members of the public to comment on the LCAPP proceeding as well as on the proposed recovery through electric distribution rates of any costs associated with LCAPP. The Board also provided opportunity for the public to submit written comments by sending a letter or e-mail to the attention of the Secretary of the Board.

On February 23, 2011, the LCAPP Agent's initial draft Standard Offer Capacity Agreement ("SOCA") was posted for public review and comment on a dedicated LCAPP website. After reviewing all the comments submitted, on March 1, 2011, the final proposed SOCA was posted on the LCAPP website and subsequently on the Board's website. On March 7, 2011, entities that previously submitted pre-qualification applications and who were pre-qualified by the LCAPP Agent, submitted their binding bid price and terms to be evaluated by the LCAPP Agent. On March 15, 2011, the LCAPP Agent's recommended selection of qualified bidders was submitted to the Board. The Agent's recommended selection was posted on the LCAPP website as well as on the Board's website.

On March 21, 2011, the LCAPP Agent submitted to the Board a report ("LCAPP Report") explaining the portfolio of statutorily required benefits (economic, community and environmental) supporting the recommended selection of qualified bidders to be awarded SOCAs. On March 29, 2011, the Board issued an order ("March Order") which, among other things, accepted the LCAPP Agent's recommendations as set forth in the LCAPP Report and awarded SOCAs to the following qualified generators: Hess Newark Energy Project, NRG Old Bridge Clean Energy Center, and Woodbridge Energy Center.

On April 8, 2011, the EDCs filed a motion requesting that the Board reconsider its ruling in the March Order. The EDCs asserted that the utilities were denied due process and that the final SOCA violated what they saw as the LCAPP Law's requirement that selected eligible generators must clear the PJM Base Residual Auction each delivery year of the SOCA. By Order dated May 4, 2011, the Board approved the executed SOCAs as LCAPP compliant. By order dated May 20, 2011, the Board denied the EDCs' motion for reconsideration finding that nothing in the EDCs' motion changed the conclusions reached by the Board on its March Order.

On May 27, 2011, the Board issued an Order ("May Order") initiating a new proceeding under Docket No. EO11050309 to continue investigating New Jersey's electric capacity needs as well as other issues associated with transmission planning, the proper functioning of the power market and new entry related issues. The May Order also designated President Solomon as presiding officer on this matter. On May 27, 2011, the Board's Secretary issued a notice of a legislative-type hearing to be held on June 17, 2011, ("June Hearing") under this docket. The following entities/persons submitted written comments at or subsequent to the June Hearing: Rate Counsel, Hess Corporation ("Hess"), the Retail Energy Supply Association ("RESA"), the COMPETE Coalition ("COMPETE"), APPA, the Public Power Association of New Jersey ("PPANJ"), the Chemistry Council of New Jersey ("CCNJ"), CPV, Gerdau Ameristeel US, Inc. ("Gerdau Ameristeel"), the Electric Power Supply Association ("EPSA"), the IMM, Comverge, the EDCs, PJM, the PJM Power Providers Group ("P3 Group")[27], NRG Energy, Inc. ("NRG") and the Sierra Club. These comments are posted on the Board's website[28].

On September 28, 2011, the Board's Secretary issued notice of a second legislative-type hearing. This October Hearing was held under Docket No. EO11050309. The notice is posted on the Board's website[29].

The following entities/persons submitted written comments at or subsequent to the October Hearing: Rate Counsel, Hess, the EDCs, the P3 Group, Exelon, the New Jersey Energy Coalition ("NJEC"), the PJM Transmission Owners Agreement - Administrative Committee ("TOA-AC"), Calpine Corporation ("Calpine"), the Commerce and Industrial Association of New Jersey ("CIANJ"), the New Jersey State Chamber of Commerce ("Chamber of Commerce"), the Independent Energy Producers of New Jersey ("IEPNJ"), NRG, APPA, IBEW Local 94, COMPETE, RESA, the IMM, Honeywell, Inc. ("Honeywell"), Public Service Enterprise Group ("PSEG"), The Non-Profit Governmental Organization commenters ("NGO Commenters") [30], H-P Energy Resources, L.L.C. ("H-P Energy") and the Safeway Companies ("Safeway"). These comments are posted on the Board's website[31].

B. THE FEDERAL PROCESS

The LCAPP Law requires selected eligible generators, with Board approved and executed SOCAs, to participate in and clear the BRA. On February 1, 2011, the P3 Group filed with FERC a complaint against PJM under FERC Docket EL11-20 arguing that PJM's Minimum Offer Price Rule ("MOPR") was ineffective in deterring buyer market power in RPM in light of New Jersey's and Maryland's initiatives to support new generation entry through what they described as out-of market incentives. The Board filed a Notice of Intervention ("NOI") under this docket on February 22, 2011. On February 11, 2011, PJM filed with FERC proposed revisions to the MOPR language under FERC Docket ER11-2875 ("PJM MOPR Revisions Filing") pursuant to Section 205 of the Federal Power Act ("FPA"). The Board filed a NOI under this docket on February 24, 2011.

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[27] The P3 Group is a non-profit organization made up of twelve member companies, namely: Calpine Corporation; Constellation Energy Group; DPL Energy; Edison Mission Energy; Exelon; GenOn Energy Management, LLC; International Power America; NextEra Energy Resources, LLC; North American Energy Alliance LLC; NRG Energy; PPL Parties; and PSEG Energy Resources & Trade LLC.

[28] See: http://www.nj.gov/bpu/about/divisions/energy/capacity.html

[29] See: http://www.nj.gov/bpu/about/divisions/energy/capacity.html

[30] The NGO Commenters include the following entities: the Natural Resource Defense Council, the National Audubon Society, the Piedmont Environmental Council and the Sierra Club.

[31] See: http://www.nj.gov/bpu/about/divisions/energy/capacity.html

The Board filed a protest with FERC on March 4, 2011, followed by supplemental comments filed on March 21, 2011, under FERC Dockets EL11-20 and ER11-2875. In these documents, the Board argued that the New Jersey Legislature acted reasonably in light of the reliability risks affecting New Jersey, as articulated by PJM in several reports. The Board further argued that the impact of the 2,000 MW to be procured through the LCAPP was overstated because it represents only 1.3 percent of the total reliability requirements for the 2014-2015 BRA in the absence of price separation in LDAs. The Board added that RPM failed to attract new generation and remains reliant on out-of-market Reliability Must Run ("RMR") contracts to ensure reliability through transmission solutions. However, these solutions, such as the proposed Susquehanna-Roseland 500 kV transmission line, cannot and may not be delivered in time to remedy the reliability concern. The Board then asked FERC to: (i) deny the P3 Group's Complaint, and (ii) reject PJM's Tariff changes to the MOPR because they were not properly vetted through the stakeholder process and thus the Commission did not have sufficient facts in the record to approve the Tariff changes.

On April 12, 2011, FERC issued an order ("MOPR Order")[32]: (i) accepting PJM's Tariff changes subject to certain conditions; (ii) addressing the P3 Group's issues for immediate consideration, and (iii) denying without prejudice the P3 Group's request on the deferred issues. Specifically, the MOPR Order made the following changes to the PJM Tariff:

- Updated the MOPR reference values as they relate to calculating the net cost of new entry ("Net CONE");
- Raised the threshold of the MOPR conduct screen from 80% to 90%;
- Eliminated the net-short requirement whereby the MOPR would only apply to a seller who buys substantially more capacity from the RPM auction than it sells into it ("Net-Short Buyer");
- Eliminated the MOPR impact screen, which compared the capacity clearing price with and without mitigation. The impact screen excluded from mitigation below-cost sell offers that did not result, by themselves, in a decrease of capacity prices either by $25/ MW-day or by 20 percent —30 percent depending on the size of the zone;
- Directed PJM to propose Tariff revisions allowing the IMM and PJM to review the costs of mitigated sell offers that may be justified if consistent with the real levelized (one year), competitive, cost-based, fixed, justified Net CONE;
- Eliminated the state MOPR exemption for any planned resource being developed in response to a state regulatory or legislative mandate to resolve a projected capacity shortfall, as determined pursuant to a state evidentiary proceeding that includes due notice, PJM participation and an opportunity to be heard. The LCAPP Law relied upon the existence of this exemption;

[32] 135 FERC ¶ 61,022 (APRIL 12, 2011)

- Added solar and wind to the list of resources that can be exempted from the MOPR and eliminated the MOPR exemption for upgrades and additions to existing capacity resources;

- Directed PJM to submit Tariff revisions addressing the possible bypass of the MOPR by resources that receive interconnection service before clearing the BRA and are therefore no longer classified as planned generation capacity resources;

- Eliminated the sunset provision, pursuant to which the MOPR automatically terminates when there is a net demand for new resources;

- Accepted the revised PJM Tariff provision clarifying that self-supply bidding as planned generation is subject to the MOPR;

- Accepted PJM's proposal to commit to a date-certain to file Tariff revisions addressing the New Entry Price Adjustment ("NEPA"); and

- Rejected the Board's request to establish a proceeding to review all potential RPM modifications required to ensure that RPM promotes new entry of generation resources and treats load and generation resources fairly.

On May 12, 2011, PJM filed its compliance filing with the FERC MOPR Order under Docket No.ER11-2875-002. Numerous parties filed protests against the PJM compliance filing with the MOPR Order ("MOPR Compliance Filing").

On May 12, 2011, the Board filed a request for rehearing ("Request for Rehearing") of the MOPR Order based mainly on the following grounds:

- Reliance - New Jersey relied upon FERC's previously approved MOPR exemption for state sponsored projects to foster the development of new capacity resources to address the State's reliability needs and FERC has unlawfully usurped that authority. New Jersey has seen its LCAPP initiative frustrated as a result of the MOPR Order and the reliability risk that LCAPP was designed to solve will persist as new entry of generation resources beneficial to New Jersey is further thwarted;

- Due Process – There was no opportunity for meaningful vetting of the MOPR issues through the PJM stakeholder process and thus the MOPR changes are an impermissible unexplained departure from precedent. The changes to the MOPR were not based upon sufficient evidence and therefore are an impermissible modification of the existing PJM Tariff. Therefore, FERC's ruling in the MOPR Order was arbitrary and capricious and as such beyond FERC's jurisdiction;

- Jurisdiction – The MOPR Order is an improper intrusion on the jurisdiction of state commissions. Section 201 (b) (1) of the FPA reserves to the states plenary authority over facilities used for the generation of electric energy. Moreover, the "state action" doctrine protects states from allegations that their contracting or capacity resource incentives constitute exercise of buyer's monopsony power. The FPA prohibits the Commission from directly regulating generating facilities; and

- Inadequate Alternatives – The alternatives presented to the states by the Commission are unduly burdensome and subject to substantial delay;

On June 13, 2011, FERC issued an Order granting rehearing ("Procedural Rehearing Order") of the MOPR Order for the limited purpose of further considering the issues raised in this process so that timely-filed rehearing requests will not be deemed denied by operation of law in the absence of Commission action within 30 days[33] from the date the rehearing request was filed. The Procedural Rehearing Order also directed FERC Staff to convene a technical conference within 45 days of the date of the Rehearing Order.

On June 29, 2011, FERC Staff issued notice of the technical conference ("FERC Technical Conference") to be held on July 28, 2011. On July 22, 2011, FERC Staff issued a supplemental notice of FERC Technical Conference establishing the agenda and the list of speakers, including President Solomon.

On August 29, 2011, the Board filed written comments with FERC, which reflected the issues discussed by President Solomon at the FERC Technical Conference. In these comments the Board sought a FERC ruling:

- Re-directing FERC's policy toward resolving structural seller market power through the promotion of new market entry and genuinely competitive markets, rather than burdening new entry with more stringent and unnecessary buyer market power mitigation rules;

- Reconsidering the proposal of the IMM for a new MOPR exemption available to capacity resources procured through a new, competitive, non-discriminatory auction process;

- Re-interpreting the revised MOPR in a manner that still permits states to address their particular reliability concerns through non-discriminatory, competitive procurement process, such as the LCAPP. The Board further requested that should FERC find that the LCAPP process was discriminatory because of the environmental and community criteria used in the selection process, the Commission should rule that competitive non-discriminatory state sponsored auction processes where the selection criteria accounts for reduction of structural market power as well as economic factors are exempted from the MOPR; and

- Considering the adverse consequences for PJM and other organized capacity markets associated with forcing states into opting for the Fixed Resource Requirement Alternative ("FRR") in the absence of appropriate MOPR exemptions.

On November 17, 2011, FERC issued an order ("Rehearing Order")[34] addressing: (i) the requests for rehearing of the MOPR Order; (ii) the protests against PJM's MOPR Compliance Filing; and (iii) the arguments made at FERC's Technical Conference on self supply issues. In the Rehearing Order FERC:

[33] 18 C.F.R. § 385.713 (2011)

[34] 137 FERC ¶ 61,145 (NOVEMBER 17, 2011)

- Denied rehearing of almost all the issues raised during this process. This includes FERC's elimination of the state mandated MOPR exemption on which the LCAPP Law relied. FERC granted, however, partial hearing on the issue of the standard of review applicable to the unit specific review process for MOPR exemptions.

- Accepted PJM's MOPR Compliance Filing in part and rejected it in part. FERC directed PJM to file a supplemental compliance filing within 30 days to address FERC's concerns over two issues: (i) the limit of information regarding sell offers applying for MOPR exceptions; and (ii) the application of the MOPR floor only to planned generation capacity, which according to FERC would allow resources to bypass the MOPR process by completing the interconnection process.

- Denied rehearing of the MOPR Order with respect to the issues discussed at the FERC Technical Conference. Regarding the BPU and the IMM proposal to allow resources procured through an out-of market competitive non-discriminatory process to qualify for a MOPR exemption, FERC rejected the proposal based on concerns that such a process would not prevent a resource from acquiring a discriminatory subsidy (for example through a state sponsored program) prior to the non-discriminatory process, thereby allowing a non-competitive low offer price into the RPM.

On November 25, 2011, the BPU and Rate Counsel filed with the United States Court of Appeals for the Third Circuit a Motion for review of the MOPR Order and the Rehearing Order ("Board MOPR Appeal").

C. JUDICIAL PROCESS

On February 9, 2011, PPL Energyplus L.L.C.,, and other parties, (collectively "Plaintiffs") filed a complaint ("Complaint") in the United States District Court for the District of New Jersey alleging that LCAPP violates the Supremacy Clause and the Commerce Clause of the United States Constitution. Plaintiffs' main contention is that the LCAPP Law violates Part II of the Federal Power Act, which provides FERC with exclusive jurisdiction to regulate wholesale electricity sales. Plaintiffs also claim that the LCAPP Law favors in-state companies at the expense of out-of state companies. In lieu of answering the complaint, the Defendants, President Solomon, Commissioner Asselta, Commissioner Fiordaliso, and Commissioner Fox, filed a Motion to Dismiss the Complaint pursuant to Federal Rule of Civil of Procedure 12(b)(1) and Rule 12(b)(6). On October 20, 2011, the Board's Motion to Dismiss was denied. Parties are currently in the discovery process pursuant to a court-ordered discovery schedule.

On May 13, 2011, Exelon Generation Company L.L.C. and PSEG Power L.L.C. ("Generators") appealed the BPU's decisions entered on March 29, 2011 and May 4, 2011 to the Superior Court of New Jersey- Appellate Division. Generators contend that (1) the LCAPP proceeding was inconsistent with due process requirements, (2) the form of the SOCA is inconsistent with the requirements of the LCAPP statute, (3) the Board's decision was arbitrary and capricious, and (4) the Board's Orders were contrary to the public interest.[35]

On June 24, 2011, the EDCs appealed the BPU's decisions entered on March 29, 2011, May 4, 2011, and May 20, 2011 to the Superior Court of New Jersey- Appellate Division. Appellants contend (1) that the process used by the Board in selecting the bidders to receive SOCAs in the LCAPP solicitation failed to meet due process requirements, (2) that the Board's decision was arbitrary and capricious, and (3) that the approved form of SOCA is inconsistent with the LCAPP statute.[36] On August 1, 2011, Rate Counsel filed a Motion to Dismiss the Appeal, which was denied.

On August 8, 2011, the Generators filed a Motion to Consolidate the appeals. That motion was denied. On September 2, 2011, the EDCs filed a Motion to Settle the Record with the Board. Hess Newark, L.L.C. filed Opposition papers ("Opposition") dated September 12, 2011. On September 16, 2011, the Board filed a Response to the Motion. On September 23, 2011, the EDCs submitted a Reply to the Opposition and a Response ("Reply"). In the Reply, the EDCs moved to amend the Motion to include an additional item. On November 9, 2011, the Board denied in part and granted in part the EDCs' Motion. As directed in the Board Order, Board Staff filed an Amended Statement of Items Comprising the Record to reflect the decision by the Board on November 9, 2011. The Generators filed a similar Motion to Settle the Record on or around November 4, 2011. This Motion is pending before the Board. Briefs have not yet been filed with the Appellate Division, and the merits of the cases have yet to be heard.

IV. ANALYSIS AND RECOMMENDATIONS

This following analyses and recommendations draw upon the written and oral testimony provided during the two Board-sponsored capacity investigation hearings, information gathered from stakeholders, other state and federal agencies and various organizations sharing New Jersey's concern regarding barriers to new generation entry in the region.

A. ACTION AT FEDERAL AND REGIONAL LEVEL

The LCAPP process has provoked discussion at the regional (PJM) and federal level about barriers to new generation entry in constrained regions with typically higher capacity prices. Partly as a result of these discussions, the PJM stakeholders are currently discussing PJM Tariff revisions to the MOPR, RPM, the FRR, demand response regulations, and the Regional Transmission Expansion Planning ("RTEP") process. Additionally, FERC has rendered decisions that impact New Jersey's efforts to facilitate the development of new generation capacity in the state and region.

This section reviews the reforms being considered under the auspices of PJM, covering reforms likely to result in PJM Tariff filings between December 2011 and February 2012,

[35] See Notice of Appeal and Case Information Statement in Docket No.: A-4467-10.
[36] See Notice of Appeal and Case Information Statement in Docket No.: A-5192-10.

as well as the more long-term reforms under consideration. The review includes descriptions of Board activities to date as well as Staff's recommendations.

1. Interconnection Reform

Interconnection issues associated with new entry of capacity in New Jersey were discussed at the Board's Technical Conference. On February 16, 2011, the PJM's Markets and Reliability Committee ("MRC") formed the Interconnection Process Senior Task Force ("IPSTF") to address possible enhancements to the PJM interconnection process. Testimony presented by Hess at and subsequent to the June Hearing indicated that interconnection barriers are the primary obstacle to entry of new generation in New Jersey. See Hess's comments found on the New Jersey Board of Public Utilities website[37],.

On September 14, 2011, the Board sent a letter to the PJM Board encouraging further discussion of several solutions under consideration in the IPSTF. Specifically, the Board supported further discussion and consideration of: (i) changes to the involvement of incumbent transmission owners in interconnection studies; (ii) the break-away proposal; (iii) changes to the duration and use of the Capacity Interconnection Rights ("CIRs"); (iv) modeling of retirements in the interconnection process; (v) establishing a separate queue for projects under 20MW; and (vi) eliminating stability analysis from System Impact Studies in certain non-constrained areas. PJM Stakeholders specifically addressed the issues raised by the Board in a meeting later in September 2011.

At the October Hearing, the Board specifically asked stakeholders to discuss in their testimonies possible barriers to new entry resulting from PJM's current interconnection process. Many stakeholders including Rate Counsel, Hess, the P3 Group, the TOA-AC, the IMM, PJM and the IEPNJ, raised interconnection issues, and generally agreed with the need to change PJM's interconnection process. However, there was broad disagreement as to the level of reform needed and the specific solutions that should be filed with FERC.

PJM is expected to file with FERC in February 2012 Tariff revisions incorporating some of the proposed solutions to the interconnection process discussed in these proceedings. PJM's testimony presented at and subsequent to the October Hearing proposes the following "initial enhancements" to be possibly filed in February with FERC: (i) moving to a six-month interconnection queue cycle from existing three-month interconnection queue cycle; (ii) introducing a "sliding queue" process that would allow projects with material system size modifications to slide to the beginning of the next interconnection queue; (iii) establishing a separate queue for projects under 20MW; and (iv) modifying several provisions concerning utilization of CIRs and related suspension rights. PJM's testimony regarding longer-term solutions, explains some concerns with the break away proposal,[38] and notes that although PJM stakeholders are considering allowing third parties to provide cost estimates for interconnection reinforcements, these

[37] See: http://www.nj.gov/bpu/about/divisions/energy/capacity.html

[38] See PJM Reply Comments to the October Hearing at page 9

estimations would have to conform with the transmission owner's (TO's) design specifications and would require interaction with TO's engineers.

Recommendation

Staff agrees with Rate Counsel, Hess, and other stakeholders that interconnection costs and interconnection delays are two significant barriers to the entry of new generation in New Jersey and the region serving New Jersey. Staff believes that the conduct of interconnection studies by the transmission owning affiliates of incumbent generators represents a substantial conflict of interest and potential for unmonitored exercise of market power. Staff recommends that the Board intervene and file comments with FERC regarding the PJM Tariff revisions expected to be filed in February 2012. If the solutions to the PJM interconnection process proposed in February conform to those explained in PJM's testimony, Staff recommends that the Board generally support these solutions, but request that FERC establish a deadline for a PJM filing addressing any long-term solutions that may not be offset by the upcoming February 2012 PJM filing. Furthermore, these reforms should unequivocally provide generators with the right to engage independent, third party transmission engineering consultants to conduct their interconnections studies. Finally, Staff urges the Board to support the queue break away proposal which will ensure that a generator's place in the transmission queue reflects project viability and not simply the date of request for interconnection.

2. MOPR Reform

The success of LCAPP depends in singular measure upon the ability of generation capacity contracted under the attendant SOCAs to clear PJM's annual BRA. Specifically, in order to avoid default, a SOCA unit must clear in one of two successive BRAs, regardless of whether the offer price into the auction is mitigated or not.[39] The application of PJM's MOPR relative to SOCA price offers in the BRA can play a determinative role in the prospect of the capacity clearing the auction and avoiding default. FERC's most recent November 17, 2011, Rehearing Order in the MOPR proceeding is thus material to the future viability of the SOCAs and LCAPP itself.

The Rehearing Order reaffirmed certain relevant determinations rendered in FERC's MOPR Order regarding the application of the PJM MOPR to the BRA price offers of state-sponsored projects such as those originating under the LCAPP. In particular, the Commission upheld its earlier determination to eliminate the state mandate exemption from MOPR, which had, prior to the MOPR Order, exempted state sponsored projects from having BRA bids mitigated to higher, purportedly competitive levels. BPU's request on rehearing that FERC reverse its MOPR Order determination and re-establish the state mandate exemption or, in the alternative, grandfather the capacity acquired through the LCAPP was rejected by the Commission, setting up the present dilemma of how to proceed with LCAPP under a stifling MOPR imposition.[40]

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[39] LCAPP Agent's Report at 22-23.

[40] 137 FERC ¶ 61,145 at P 91.

The MOPR purportedly functions to interdict anti-competitive bids into the BRA, defined as below-cost offers submitted with the purpose of suppressing the auction clearing price. Entities in a net-short position would, according to this argument, be in a position to capitalize on capacity purchases at artificially suppressed prices by virtue of below cost self-supply offers, thus exercising buyer market power.[41] Because the SOCAs require that the contracted unit capacity clears the BRA, it has been argued that the SOCA units would have been bid in at zero priced offers, assuring that they would clear. The SOCA-specified contract for differences between the BRA clearing price and the contracted capacity price ensured that the bidders' total capacity revenues would have been insulated while behaving as price takers in the BRA. Zero priced or other below cost offers designed to clear the BRA from new entry capacity are now prohibited. FERC maintains that an economic offer for such new entry is the equivalent of the administratively-determined net cost of new entry ("net CONE") for the particular type of plant (i.e., combustion turbines, combined cycle units, etc.). FERC's MOPR determination will now subject to upward mitigation new entry price offers submitted below the "already discounted" level of 90 percent net CONE. Such price offers will henceforth be mitigated upward to the 90 percent of net CONE for the particular type of asset, which the Commission characterizes as a "presumptively economic" price offer level.[42]

Upward price offer mitigation executed under the MOPR would subject SOCA bids to the prospect of not clearing the BRA because the mitigated price could exceed the actual BRA clearing price. For example, PJM's 2010-updated net CONE for a combined cycle plant is $205.40 per MW-day, which at 90 percent of net CONE produces a MOPR mitigation price of $184.86 per MW-day.[43] Assuming FERC's MOPR determination was in effect for the May 2011 BRA and that the three SOCA units bid into that auction, the mitigated price of $184.86 for a combined cycle would have caused both the NRG Old Bridge Clean Energy Center and the CPV Woodbridge Energy Center to fail to clear given that the relevant MAAC LDA cleared at a lower price of $136.50 per MW-day. The higher clearing price of $225.00 per MW-day for the PS-NORTH LDA emerging from last May's auction indicates that the Hess Newark Energy Center capacity would have cleared the BRA at the mitigated offer price of $184.86.[44] The historic volatility of BRA clearing prices in PS-NORTH and EMAAC, however, ensure that MOPR-mitigated SOCA offers face critical uncertainty in clearing the BRA and meeting their commencement dates. Should FERC's determination on the application of the MOPR to state sponsored projects prevail, it could fundamentally undermine the currently constructed LCAPP paradigm for acquiring capacity for New Jersey.

SOCA units, in addition to all other new merchant capacity facing MOPR mitigation in the BRA, could, under the provisions of the FERC's Rehearing Order, opt for a unit-specific review of their costs and, if successful in that review, avoid MOPR offer price mitigation. The Commission's MOPR Order provided for an exception process wherein a

[41] 137 FERC ¶ 61,145 at P 87, 205 and 135 FERC ¶ 61,022 at P 6.

[42] 137 FERC ¶ 61,145 at P 36, 43, 207 and 135 FERC ¶ 61,022 at P 66.

[43] *Ibid*. at P 50.

[44] http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/20110513-2014-15-base-residual-auction-report.ashx at 1.

generator whose capacity would otherwise be subject to MOPR mitigation could request a unit-specific review by the IMM of the cost structure of its sell offer, with the result appealable to PJM, should the generator believe the IMM's findings are not in its interests. Adopting the proposal of PJM, FERC initially determined that such sell offer cost justification would have to be "consistent with the competitive, cost-based, fixed, nominal levelized, net cost of new entry were the resource to rely solely on revenues from PJM-administered markets." Sell offers below the MOPR mitigation level but consistent with this standard could be exempted from mitigation and offered in as requested by the generator.[45]

Upon further review and in consideration of public comments, FERC granted rehearing of this standard of review in its Rehearing Order, rendering it more flexible to the requesting generator. Specifically, the Commission directed PJM to file a compliance tariff eliminating the requirement that generators must use the nominal levelized cost recovery methodology in the unit specific review.[46] FERC's revision of the unit-specific review process is designed to recognize the legitimate competitive cost advantages inherent in certain established business models, including a generator's specific financial condition, tax status, access to capital or other factors that would legitimately and favorably affect the entity's actual net project cost.[47] New entry that can justify a cost-based price offer lower than the MOPR-mitigated price would be permitted to bid that lower price into the BRA; if the offer clears the auction, the unit would henceforth not be subject to future MOPR mitigation.[48] This process provides the potential for relief from a stifling MOPR application that could strand new capacity by forcing price offers above the levels of resource clearing prices.

However, the Commission's determination also appears to introduce a simultaneous review of unit-specific offers by both the IMM and PJM, rather than the echeloned review by the IMM followed by PJM, if necessary, as specified in the MOPR Order. The MOPR Order prescribed that generator requests for unit-specific determinations would be reviewed first by the IMM, with a secondary PJM review should the generator desire an appeal of the IMM's findings.[49] The Rehearing Order appears to re-affirm this two-step review process only in cases where the generator is not satisfied with the IMM's determination. In cases where the generator's review was satisfactorily conducted by the IMM, there would appear to be no avenue for PJM intervention in such determination, and the offer would be sanctioned for bid into the BRA.

The Commission directed PJM to file a compliance tariff incorporating its revisions to the unit-specific review standard and the review process.[50] However, the Rehearing Order also references PJM's proposal to require the generator to submit simultaneous review

[45] 135 FERC ¶ 61,022 at P 121-122.

[46] 137 FERC ¶ 61,145 at P 73-74.

[47] *Ibid*. at P 213.

[48] *Ibid*. at P 132.

[49] 135 FERC ¶ 61,022 at P 121-122

[50]137 FERC ¶ 61,145 at P 66, 74.

requests to both the IMM and PJM, and providing that PJM may also elect to review the IMM's [findings] on its own initiative."[51] This presents the potential for conflict between an initial independent assessment of the request by the IMM and a simultaneous review and finding by PJM.

It is not clear, and it will not be clear until the compliance filing is made by PJM, whether PJM's tariff language would permit PJM to overrule an IMM finding that a unit-specific offer *is justifiably cost-based* and appropriate for offer into the BRA. Accordingly, Staff recommends that the Board be prepared to ensure an independent review of unit-specific offers by the IMM without the potential for PJM overruling an IMM determination favorable to the generator. Should the PJM compliance filing undermine FERC's originally prescribed review process, Staff recommends that the Board pursue all available means to ensure a proper final disposition by FERC.

In post-technical conference Comments filed at FERC, Staff urged the Commission to either restore the state mandate exemption to the MOPR or grandfather the LCAPP units; in lieu of adoption of those recommendations, Staff urged the Commission to adopt a non-discriminatory auction construct that would be exempt from MOPR application. The non-discriminatory auction concept was proffered by the IMM as a resolution of the MOPR predicament facing PJM states with legitimate concerns over reliability; specifically, the IMM proposes a transparent, competitive long-term procurement auction that is accessible to new and existing generation. Capacity procured through such mechanism would be exempt from the MOPR.T[52] Staff indicated concurrence with the IMM concept, but modified it to include a provision that winning capacity resources be selected based not only upon lowest bid but also the extent to which the particular project reduced structural market power in the relevant locational market. The intent behind Staff's modification was to ameliorate some of the endemic structural market power evident in the RPM market, which Staff concludes is partially responsible for RPM's failure to deliver new capacity to New Jersey area locational markets.[53]

FERC rejected the IMM auction proposal in its Rehearing Order, without consideration of the Staff's market power mitigation modification. The Commission found that the IMM-proposed competitive auction would not prevent participants from securing a discriminatory subsidy *prior* to offering into the competitive auction, in turn permitting a non-competitive offer to be bid into the BRA without being subject to the MOPR.[54] FERC's problems with the operation of the competitive auction could certainly be remediated through obvious review protocols applicable to project bids. However, such protocols were not submitted as part of the comments of either the IMM or Staff, who merely sought Commission approval of the concept. It is therefore conceivable that the Commission would entertain a more thoroughly developed auction regime either on appeal or in a subsequent filing.

[51] *Ibid.* at P 215.

[52] *Ibid.* at P 179.

[53] *Ibid*. at P 201.

[54] *Ibid*. at P 210.

The non-discriminatory auction concept does represent a feasible alternative to the MOPR impediments standing in the way of a successful implementation of LCAPP. Accordingly, Staff recommends that the Board direct further development of the IMM auction concept, as modified to reduce structural market power, as an alternative to the LCAPP should the near term experience of the SOCAs clearing the BRA become problematic.

Recommendation

Staff recommends that the Board continue to pursue the Board MOPR Appeal filed on November 25, 2011, seeking review of the MOPR Order and Rehearing Order.

Staff further recommends that the Board monitor the success of the three contracted SOCA projects in clearing the May 2012 and May 2013 BRAs under the revised MOPR. Failure of the SOCAs to clear the May 2012 BRA may indicate that the LCAPP paradigm, as currently constructed, may be incapable of developing State-identified capacity requirements under existing FERC policies. In this case, the Board should direct Staff to begin constructing an LCAPP II design that incorporates a capacity procurement mechanism modeled on the aforementioned non-discriminatory, competitive auction proposal of the IMM, as modified by the Staff's market power mitigation feature, for use in contracting capacity for bid into the May 2013 BRA.

Finally, Staff recommends monitoring the PJM compliance tariff filing at FERC related to the unit-specific review and MOPR exception process discussed above. This effort should be geared to supporting FERC-approved PJM tariff language that provides for an initial review of unit-specific offers by the IMM; with appeal rights to PJM afforded to the generator should the generator believe that the IMM's review decision is not in its best interests.

3. Regional Transmission Expansion Plan Reform

Transmission constraints reduce the size of markets and increase the potential for the exercise of seller market power. Conversely, the expansion of transmission infrastructure serves to increase the supply of energy and capacity, thereby reducing or resolving price differentials between constrained and unconstrained areas. For this reason, transmission expansion is a key factor considered when deciding to invest in new generation facilities.

PJM is currently looking at two broad issues concerning the RTEP: (i) reforms to transmission planning and cost allocation in compliance with the requirements of FERC Order 1000[55]; and (ii) coordination of certain aspects between the RTEP and RPM.

Transmission Planning and Cost Allocation

[55] 136 FERC 61,051 (July 2I,20ll)

The Board has addressed transmission planning and transmission cost allocation issues primarily under three FERC Dockets: (i) Docket AD09-8 - FERC Notice of Requests for Comments on Transmission Planning Processes under Order 890; (ii) Docket EL05-121 - FERC Paper Hearing in response to the decision by the United States Court of Appeals for the Seventh Circuit remanding to the Commission the determination of the appropriate allocation methodology to be used by PJM for new transmission facilities that will operate at a voltage level at or above 500 kV ("Backbone Upgrades"); and (iii) Docket RM10-23 - FERC Notice of Proposed Rule Making ("NOPR") on Transmission Planning and Cost Allocation.

On July 21, 2011, FERC issued Order 1000 on transmission planning and cost allocation. Among other things, Order 1000 established certain cost allocation principles for regional and interregional planning, required public policy to be considered in transmission planning, eliminated the right of first refusal of incumbent transmission owners, and enhanced the interregional coordination requirements of Order 890. On September 12, 2011, the Board filed a request for clarification, or in the alternative, rehearing of Order 1000. The Board specifically sought clarification from FERC regarding of the following issues:

- New transmission infrastructure cannot be planned for or built accounting solely for public policies ("Public Policy Projects"). Should FERC insist on allowing Public Policy Projects in transmission planning processes, Order 1000 must clarify that: (i) the Commission's backstop authority cannot be exercised to force construction of those Public Policy Projects; and (ii) transmission rate incentives granted by the Commission to these Public Policy Projects will not shift the risk of changing public policies to ratepayers;

- The use of future scenarios in determining who benefits from construction of new transmission lines cannot be so expansive as to introduce unnecessary speculation in new transmission cost allocation methodologies and must not be used to change cost allocation methodologies currently approved by the Commission; and

- Open stakeholder processes in transmission interregional planning processes are mandatory, not optional, particularly with regard to processes determining cost allocation of transmission facilities. States should have a key role in those stakeholder processes.

PJM stakeholders are currently discussing changes to the RTEP process in compliance with Order 1000. These changes will likely be filed with FERC in February 2012.

In the February filing, PJM intends to reform its bright-line tests[56] to include a broader range of factors affecting transmission planning, including public policy considerations. This expanded scenario planning is the so called "FYI Process"[57]. PJM stakeholders are

[56] PJM bright-line tests currently consist of a series procedures based on the North American Electric Reliability Corporation's ("NERC") standard tests for the planning process and include detailed assumptions regarding load levels, transfer levels and generation patterns. Violations are identified when NERC limits are exceeded even by 1 MW and can form the basis for PJM-directed baseline transmission solutions.

also developing expanded RTEP decision-making frameworks beyond the existing decision framework circumscribed by reliability and market efficiency considerations.

The three new decision frameworks are: (i) the "State Agreement"[58] approach; (ii) the "Critical Mass"[59] approach; and (iii) the "Proactive Building"[60] approach. As of the date of this Report, PJM is still considering whether to include in its February 2012 filing the State Agreement approach. PJM staff expects that a second filing with FERC will be submitted on October 2012. This October 2012 filing may include the Critical Mass and Proactive Building decision frameworks.

On a parallel track, the Organization of PJM States, Inc. ("OPSI") has been developing a charter for an Independent State Agencies Committee ("ISAC") to work with PJM in providing public policy inputs and developing studies taking into account different public policies scenarios. The role of the ISAC and its relation with PJM may vary as new RTEP decision frameworks are approved by FERC.

Recommendation

Staff believes that the FYI Process complies with the requirements of Order 1000 to integrate public policy into the transmission planning, while not necessarily turning public policy into transmission drivers that may justify building new transmission based solely on public policy considerations. The PJM decision frameworks are not necessary for compliance with Order 1000 requirements, and the details of their implementation need to be further vetted through the PJM stakeholder process. Furthermore, it is quite likely that uncertainty resulting from the introduction of these decision frameworks in the RTEP would adversely impact entry of new generation because of the effect transmission expansion has on energy and RPM capacity prices.

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[57] The FYI Process would provide stakeholders – market participants and states, alike – an up-front opportunity to provide input on modeling assumptions and analytical scenarios, and post-analysis opportunity to review and discuss study results. After PJM performs extensive scenario planning analyses taking into account the inputs from stakeholders, it provides the results to the market so that market participants and states can make their own informed decisions on what solution opportunities to pursue. However, while the results PJM produces could include performance of various solution options, no RTEP action would be taken by PJM with respect to such solutions within the context of the FYI process. The goal of the FYI process is to provide information that informs the decision making frameworks.

[58] The State Agreement decision framework would allow one or more states to decide how to meet their goals through transmission planning. If states can agree to specific transmission projects and cost allocation, these projects can be integrated into the RTEP.

[59] The Critical Mass decision framework would focus on reaching commitment to a transmission project justified on the basis of considering multiple drivers. This includes commitment to a transmission project that may be justified either: (i) based on one bright line driver but with capability larger than required to address that driver alone, based on the expectation that sufficient additional drivers (for example, public policy) exist to justify the additional transmission capability; or (ii) based on the cumulating of drivers when no one driver on itself can trigger a transmission expansion project.

[60] The Proactive Build decision framework would allow PJM to design new bright-line triggers related to various policy initiatives and enter transmission projects to the RTEP once those triggers are surpassed.

Staff recommends that the Board file comments to the anticipated PJM February 2012 filing generally supporting the FYI process but advising the Commission to be cognizant of the potential negative impacts that the introduction of new decision frameworks into RTEP may have on new entry.

RTEP and RPM Coordination

The Brattle Group's Second Performance Assessment of PJM's Reliability Pricing Model dated August 26, 2011 ("Brattle Report")[61], reviewed the issue of further coordination of the RTEP and RPM. Stakeholders interviewed in the process of drafting the Brattle Report indicated that greater consistency is needed between RTEP and RPM in some areas, including: (i) making sure that RPM resources failing to clear the BRA are not modeled in RTEP; (ii) conducting the BRA on a five-year forward basis to coincide with RTEP planning horizons; and (iii) resolving inconsistencies between the assumptions used in the RTEP and the transmission assumptions made in calculating the Capacity Emergency Transfer Limits ("CETL"). At the October Hearing, the Board specifically addressed this third issue and asked stakeholders to respond to the following question:

> Are there any inconsistencies between the transmission assumptions made in the PJM RTEP process and the transmission assumptions made in calculating the CETL for the LDAs modeled in RPM (e.g., double-circuit tower line criteria violations)? If so, describe them, indicate whether they can be resolved and what the effects of their incorporation into RPM would be.

Testimony presented at and subsequent to the October Hearing by Rate Counsel, the EDCs, and APPA addressed this issue. Rate Counsel argued that there is no need to impose consistency on the assumptions used for the CETL calculations for transmission planning and the nearer term CETL estimates for use in RPM auctions. Rate Counsel generally supports the recommendations of the Brattle Report to increase CETL stability and opposes including additional transmission reliability criteria that may lead to increasing LDA local capacity requirements and higher RPM prices. The EDCs generally support the recommendations of the Brattle Group to make CETL as well as RPM prices more stable, transparent and predictable. APPA believes that the inconsistencies between the RTEP and the transmission assumptions in calculating CETL highlight a "fatal flaw in the RPM market" because RPM may not be addressing key reliability criteria. APPA adds that the RPM three-year forward pricing model is not only inadequate to attract new resources with longer lead times, but it is not properly aligned with longer-term transmission planning and bilateral contracting.

On December 1, 2011, PJM filed with FERC under docket ER12-513 ("PJM December Filing") some proposed changes to the PJM Tariff based on the Brattle assessment of RPM. In particular, PJM proposes to:

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[61] See: http://www.pjm.com/documents/~/media/committees-groups/committees/mrc/20110818/20110826-brattle-report-second-performance-assessment-of-pjm-reliability-pricing-model.ashx

- Update the CONE values used in the "bottom up" analysis of the VRR curve and the screen offers of the MOPR.
- Revise the calculation methodology for energy and ancillary services ("E&A").
- Eliminate the annual capacity resources and the extended summer resources from the 2.5% holdback.

Recommendation

Staff believes that some of the recommendations of the Brattle Report regarding further coordination of RPM and RTEP could be supported, particularly, those recommendations aimed at stabilizing the CETL calculations and reducing price volatility and unpredictability in RPM markets. The December 1, 2011 filing does not address any of these Brattle recommendations. Staff recommends that the Board direct Staff to file comments with FERC in response to the PJM December Filing with the final goal of ensuring that those changes are not inconsistent with the Board's objective to promote new generation entry in the region.

4. NEPA Reform

On December 22, 2006, the Commission issued an order ("FERC RPM Settlement Order") under dockets EL05-148 and ER05-1410 approving, with conditions, a settlement filed by PJM and the PJM market participants concerning RPM. The FERC RPM Settlement Order approved the NEPA Tariff provisions for the purpose of providing new entrants in small LDAs with some cost recovery assurance in the event that their entry creates a capacity surplus resulting in significantly lower prices. This is commonly referred to as the "lumpy investment" problem.

The PJM Tariff currently allows new entrants[62] to lock in prices for three years provided they comply with the LDA impact test[63] and other qualifying requirements. A NEPA resource receives the LDA clearing price of the first delivery year and if the resource's offer clears in a subsequent BRA, that resource receives the higher of its first-year offer price or the clearing price for that subsequent BRA. In delivery years after the first year, any payment to the seller above the clearing price does not increase the clearing price received by other sellers. If a NEPA resource does not clear in the two subsequent BRAs, the initial sell offer will be deemed resubmitted at the highest price per MW at

[62] New entrants are: (i) planned generation; (ii) energy efficiency; and (iii) existing generation submitting a sell offer with an avoidable project investment recovery rate component based on a project investment of at least $450/kW

[63] The project must have a major impact on LDA price. Major impact occurs when acceptance of a NEPA offer results in a reduction in price from a level higher than 112.5 percent of Net CONE to less than 40 percent of Net CONE.

which the NEPA resource would clear the subsequent-year BRA pursuant to an optimization algorithm.

The LDA impact test is very difficult to meet and, as a result, no resource has qualified for NEPA. In 2009, PJM proposed NEPA Tariff changes to FERC to extend the assurance period from three years to up to seven years and relaxed the LDA impact test. FERC rejected PJM's proposal on the basis that the PJM proposed amendments: (i) went beyond the initial intent of addressing lumpy investment in small LDAs; and (ii) would result in price discrimination between existing and new resources. FERC recognized that a longer commitment period may aid developer in financing new entry projects but pointed out that RPM was designed to provide long-term forward price signals and not necessarily long-term revenue assurance for developers. FERC balanced the benefits of the longer commitment period to finance new entry projects against the possible uplift payments that customers may have to bear due an extension of the NEPA term and concluded that no party made the case that extending the period to five or seven years struck a better balance than the existing provisions.

PJM's MOPR Revisions Filing acknowledged the comments made by some parties that new entry requires greater revenue certainty from competitive wholesale markets than the PJM market rules currently provide. As an alternative to out-of-market mechanisms, PJM proposed to enhance RPM's NEPA rules to provide long term in-market revenue assurances. PJM proposed an October 1, 2011 deadline for filing any stakeholder vetted reforms to the NEPA process that would satisfy the twin objectives of supporting new entry while avoiding undue discrimination between new and existing resources.

The MOPR Order accepted PJM's proposal to commit to a date-certain to file revisions to NEPA. On October 3, 2011, PJM submitted to FERC an informational filing advising the Commission of PJM's intent to continue facilitating the stakeholder process with a goal of developing NEPA changes that could be filed with the Commission by November 30, 2011.

As part of the PJM stakeholder process, several NEPA extension models were discussed but the majority vote in several committees opted for keeping the status quo. Furthermore, the Brattle Report recommends that PJM not expand NEPA and continue utilizing it to mitigate the adverse effects of lumpy investments in small LDAs. According to the Brattle Report, an expanded NEPA mechanism has two main flaws: (i) it would not recognize if expanding demand response or delaying the retirement of an existing generator could more efficiently meet the short-term capacity needs until the planned transmission project is in service; and (ii) suppliers bidding with the hope to lock in a multi-year price may bid below the level supported by market fundamentals in the current auction, thus depressing the annual auction price.

On October 3, 2011, PJM filed with FERC a status report under FERC Docket No. ER11-2875 informing the Commission that the stakeholder process on possible changes to the NEPA remained on a productive path and that PJM had determined not to file changes to NEPA on October 1, 2011, as provided in the MOPR Revisions Filing. Instead, PJM advised that it will continue to facilitate the stakeholder process with a goal of developing NEPA changes that could be filed by November 30, 2011 in connection with other RPM changes.

The Board asked at its October Hearing whether a long-term fixed price signal in RPM, either through a reformed NEPA mechanism or through a voluntary auction for long-term capacity procurement, could result in more mid-merit and base load generation being built in constrained LDAs such as those in New Jersey. Testimony presented at and subsequent to the October Hearing rejects the concept of an expanded NEPA or a voluntary long-term capacity auction. The IMM believes that a competitive, non-discriminatory procurement auction would provide the same type of revenue guarantee and risk shifting as an expanded NEPA, without creating issues associated with redefining the capacity market product or discrimination between new and old units. APPA believes that because of the RPM construct, neither NEPA nor a voluntary long-term auction would be likely to provide a long-term signal at prices that are reasonable for the load serving entities ("LSEs"). Rate Counsel argues that RPM is fundamentally a one-year construct setting a price based on demand and supply for a single year and it cannot be effectively stretched to offer longer-term price assurances, through mechanisms like a modified NEPA rule. Rate Counsel does not support the establishment of a long-term voluntary auction because it does not provide any advantage over the already existing bilateral contracts, as the voluntary auction would be limited to standardized, "capacity only" products with fixed attributes and durations and no consideration of resource attributes.

The PJM December Filing included proposed clarifications to existent NEPA language and a proposal to file with FERC by August 1, 2012, Tariff changes to establish a long-term auction process that will either supplement or replace current NEPA rules.

Recommendation

Board Staff believes that the Board should not support a long-term auction process because (i) there are valid questions as to the efficiency of this construct to attract new entry vis-à-vis the risk of uplift prices that New Jersey customers may have to assume; and (ii) that a non-discriminatory, competitive auction model similar to that proposed by the IMM may be a viable alternative to both NEPA and the LCAPP paradigm (see MOPR section 5, below). Staff recommends that the Board direct Staff to monitor the PJM process preceding the August 2012 filing, and file comments along the lines described above.

5. FRR Reform

The FRR alternative allows LSEs to opt out of RPM and, instead of meeting the RPM variable resource requirement, meet a fixed capacity obligation. LSEs that choose the FRR option are subject to certain qualification requirements and face restrictions on the amount of capacity they may sell in RPM auctions.

The MOPR Order, in addressing the LSE's concerns over the elimination of the assurance to clear legitimately procured self-supply, offered FRR as a viable alternative. The Rehearing Order reiterated the availability of the FRR alternative for self-supply projects. The Brattle Report has expressed concerns that the risk of not clearing self-supplied resources in the RPM auctions due to MOPR mitigation will create a barrier to bilateral contracting and other self-supply options. This will make it more difficult and costly to hedge capacity prices, and will likely force many load serving entities that rely on self-supply to opt out of RPM through the FRR option. According to Brattle, a more widespread use of the FRR option would reduce RPM market efficiency and increase costs because it places limits on selling into RPM. These concerns were shared by the Board in its comments to the FERC Technical Conference.

In this context, the MRC passed in May 2011 a problem statement that reflected the concerns of PJM stakeholders regarding the use of FRR as an alternative to self-supply. In particular, PJM stakeholders were concerned that the FRR could not be successfully utilized by most LSEs. The problem statement explained that:

> As a practical matter, the FRR works well for larger, net long LSEs that have diverse portfolios of resources with which to satisfy their loads plus required reserves, and that can satisfy other demanding FRR prerequisites. These requirements include matching generation resources with all load in an "FRR Service Area," a term that the PJM Reliability Assurance Agreement ("RAA") restrictively defines with reference to specific metering arrangements and geographic criteria. Smaller net short LSEs simply do not have the capacity resources in place and cannot meet the prerequisites required to elect the FRR option under the current rules. Additionally, pending environmental regulations could result in significant retirements of both FRR and RPM supply, making the FRR option unworkable even for those who currently do utilize it.

On the basis of this concern, the problem statement approved two charges for the MRC relating to the FRR alternative: (i) to examine current RPM and FRR rules, and (ii) to identify potential changes to make FRR rules less restrictive to accommodate LSE clearing issues as well as uncertainty of future supply given large numbers of existing unit retirements. To the date of this Report, the MRC has not made much progress on these matters.

Recommendation

Staff recommends that the Board monitors the discussions at PJM regarding changes to the FRR rules and takes an active role in promoting those changes necessary to facilitate an FRR alternative in New Jersey. Should PJM file Tariff changes to the FRR rules, Staff recommends that the Board file comments with FERC in support of those changes that facilitate the use of an FRR alternative in New Jersey.

6. Demand Response

Along with numerous other states, New Jersey has long-recognized the cost-effectiveness of demand response resources in helping to support electricity reliability, along with generation and transmission solutions. On the Federal level, New Jersey has expressed such support, at times in joint filings with other states, in response to FERC-issued NOPRs on demand response initiatives and to PJM Federal compliance filings. Early on, New Jersey supported the PJM Emergency Load Response Program and the PJM Economic Demand–Side Response Program. More recently, New Jersey has intervened, and at times commented, in a number of FERC proceedings on demand response, regarding the issues of: Sufficient compensation for demand-side resources;

the need for integration of demand response into any scarcity pricing mechanisms and methodologies; potential issues surrounding demand response saturation in the wholesale market; price-responsive demand within PJM markets; and the need for accurate demand response measurement and verification methodologies in PJM programs.

In 2007, New Jersey expressed its support for those parties that recommended to the Commission the extension of the PJM Economic Demand Response program Tariff provisions beyond the December 31, 2007 expiration date. In that year, certain provisions of PJM's Open Access Transmission Tariff ("OATT") would have allowed the expiration of payments for customer curtailment when the locational marginal price ("LMP") exceeded a particular threshold. New Jersey argued that an extension of the incentive payments for demand response was in the public interest, as it would provide market stability until the stakeholders could reach some resolution on the issues surrounding the dispute.

During the past few years, New Jersey has argued strenuously for sufficient compensation to encourage increased and continued demand response participation, specifically supporting the full LMP for such resources in PJM's wholesale marketplace. The State has also argued for an appropriate demand response performance measurement, based upon an entity's reduction from its peak load contribution value, so that demand response can continue to provide cost-effective reliability to the region.

In addition to filings made at FERC in support of cost-effective demand response, New Jersey has expressed support and encouraged such resources in regional venues as well as forums provided by PJM. The State recognizes the effectiveness of working with other state regulatory agencies, and has pursued a collaborative approach in support of demand resources through participation in several organizations, including: The Mid-Atlantic Distributed Resource Initiative ("MADRI"); OPSI; and the National Association of Regulatory Utility Commissioners ("NARUC").

In 2006, New Jersey and the other original MADRI states, worked with PJM in pursuit of an objective study to identify and quantify the impact of demand curtailment in the PJM region. Accordingly, the Brattle Group, retained on behalf of PJM, produced a report entitled *Quantifying Demand Response Benefits in PJM,* (January 29, 2007). The report estimated the benefits from demand response, including the economic benefit and the long-term capacity benefit to all consumers, as well as to demand response program participants. At that time, the report provided a rough savings estimate of $73 million per year long-term capacity benefit to demand response program participants, based upon a modest 3 percent curtailment of load in five zones within PJM. These estimated savings result from reduced reserve adequacy capacity requirements due to load shape modifications associated with peak demand reductions. Additional benefits such as enhanced competitiveness of energy and capacity markets, reduced price volatility, and the provision of insurance against extreme events, were noted but not quantified.

New Jersey also participated in the PJM Symposium on Demand Response in May 2007; commented on early versions of the Demand Response Roadmap for the PJM Region; and endorsed the Roadmap, as part of MADRI. The Roadmap identified the need for coordination between the retail and wholesale markets in order to increase demand response participation in PJM energy and capacity markets.

Recommendation

PJM is in the process of implementing many initiatives to support demand response and make it easier for these resources to participate and be adequately rewarded through PJM's energy and capacity markets. Staff recommends that the Board continue to actively monitor PJM's demand response reforms and the development of any new demand response capacity products in order to maximize the State's demand response resources' participation in these markets.

B. ACTION AT STATE LEVEL

Energy costs and reliable energy supplies are two primary concerns associated with New Jersey's ability to retain existing businesses, attract new enterprise, and create jobs in a competitive global economy. Indeed, New Jersey has historically crafted sustainable energy policies and programs that sought to balance the goal of economic development with the need to provide reliable supplies of affordable energy while improving environmental quality.

The LCAPP Law constituted the New Jersey Legislature's response to serious reliability concerns arising from the lack of new generation entry in the region. Since the LCAPP Law was enacted, the Board has not only complied with its legislative mandate, but has also defended the legitimate right of the State to take action when the PJM markets fail to provide expected results. Currently, New Jersey ratepayers pay the highest capacity prices in PJM, reflecting locational constraints in the region. However, no new generation is being built in regions where capacity prices are the highest. Furthermore, New Jersey ratepayers are bearing the cost of out-of-market, reliability must run ("RMR") contracts put in place to ensure reliability when the announced retirement of a generation unit leaves insufficient time to develop more cost-effective transmission or location-specific generation solutions.

Staff believes that reliability risks in New Jersey persist specially in PS North. This is because PJM's claims that RPM satisfies resource adequacy requirements ignores the distinction between reliability concerns based on (1) localized transmission security needs, and (2) resource adequacy needs. Capacity markets are designed to address resource adequacy concerns. However, where a generation retirement would create highly localized transmission security violations, capacity markets are not well-suited to identify replacement capacity because LDA price signals may add resources in any location within the same LDA not necessarily in the location where the transmission violations are to occur. In other words, while the resource adequacy in an LDA may be sufficient, new resources added in that LDA may not be able to resolve the reliability needs in a location where power system flows are outside specified design or operating limits as a result of a generation retirement. In these cases, and in the absence of preventive state action, RMR contracts may temporarily be the only available solution to localized reliability problems.

This section discusses the various ways in which New Jersey can promote new generation entry to supplement LCAPP and to ensure reliable and cost competitive supply of electricity for New Jersey ratepayers.

1. Market Power and Affiliate Relations

In these proceedings, and most specifically at the October Hearing, the Board raised the issues of structural market power and market power abuse as constituting potential barriers to new entry of generation in the region..

The EDCs testified that they are not aware of any studies or opinions alleging that abusive behavior or market power problems have been observed or even suspected in relation to the RPM market. The P3 Group believes that exercise of market power from either the buy or sell side is an impediment to a properly designed and well functioning market, but did not explain whether market power abuse exists in New Jersey and how it potentially affects new entry. The TOA-AC argued that FERC-approved and PJM-overseen controls significantly minimize the risk that any particular TO can exercise market power but can cause delays in the interconnection process to benefit incumbent generation affiliates. PSEG testified that having generators with high market concentration or affiliate relationships with transmission companies does not necessarily cause the market to be uncompetitive or discriminatory, and that FERC has found that the PJM market monitoring and mitigation rules are sufficient to address the potential exercise of market power included in the PJM-East submarket[64]. Exelon testified that there is no market power abuse and that the results of the RPM market are competitive due to the stringent participation and bid-setting rules that prevent seller-side market manipulation[65]. APPA claimed that to the extent that a financial incentive exists for the TOs and their generation affiliates to constrain the supply of generation, it might be beneficial to explore allowing third parties to conduct the interconnection studies or to find other ways to provide the necessary discipline and oversight[66]. The IMM testified that the Board should look at barriers to entry in the interconnection process[67]. Finally, Hess testified that irregularities in the interconnection process resulting in delays and high interconnection costs are a barrier to the entry of new generation in the region[68].

At the state level, the Electric Discount and Energy Competition Act of 1999 (“EDECA”)[69] contains basic affiliate relations principles under N.J.S.A. 48:3-49 et seq. N.J.S.A. 48:3-56.f. (1) requires the Board to adopt rules concerning the affiliate relation standards as necessary 1) to ensure that electric public utilities or their related competitive business

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[64] PSEG reply comments to the October Hearing at page 3.

[65] Exelon reply comments to the October Hearing pages 27 and 28

[66] APPA comments to the October Hearing at page 4

[67] IMM comments to the October Hearing at page 4

[68] Hess Comments to the October Hearing page 1

[69] N.J.S.A. 48:3-49 et seq

segments do not enjoy an unfair competitive advantage over other non-affiliated purveyors of competitive services and 2) to monitor the allocation of costs between competitive and non-competitive services offered by an electric public utility. The Board has adopted Affiliate Relations Rules under N.J.A.C. 14:4-3 et seq. to enforce the principles established in EDECA, and has adopted additional rules under N.J.A.C. 14:4-4A to supplement the gap left after repeal of the Public Utility Holding Company Act ("PUHCA"). The principal components of the Affiliate Relations Rules fall into four main categories: (i) non-discrimination, (ii) information disclosure (iii) separation and (iv) competitive products and/or services offered by the public utility or related company.

Recommendation:

After reviewing the applicable rules dealing with market power and affiliate relations issues, as well as the testimony presented in this proceeding, Staff believes that an enhanced investigation of compliance with and a stricter enforcement of existing Affiliate Relations Rules is required.

Focused Audits of EDCs

Audits are a monitoring device designed to give the Board the knowledge needed to effectively enforce its policies and regulations. Under N.J.S.A. 48:3-56.f. (1), the Board shall conduct audits, at the expense of the electric public utilities, to ensure compliance with the Board's Affiliate Relations Rules, among others. The Board shall hire an independent contractor to perform such audits and pursuant to N.J.S.A. 48:3-56.f. (2) these audits shall be conducted every two years.

Under N.J.S.A. 48:3-56.f. (4), if the Board finds, as a result of any such audit, that substantial violations of EDECA or the Board's Affiliate Relations Rules have occurred resulting in unfair competitive advantages for an electric public utility, the Board shall: (i) order the electric public utility to be functionally separated from the related competitive business segment, (ii) order the electric utility to establish and provide such services through a structurally separate business unit or units or (iii) order the electric public utility to divest itself of any business units that provide such competitive services. Even without an audit, N.J.S.A. 48:3-56.h gives authority to the Board to take appropriate and increasingly stringent action in the event that the Board determines, after hearing, that recurring and significant violations of its rules have occurred. These stringent actions include the issuance of an order that an electric public utility or its related competitive business segment: (i) cease the offering of a competitive service, (ii) functionally separate or structurally separate its competitive service offering from non-competitive business functions or (iii) divest itself of such services. The Board, however, has no authority under EDECA to order divesture and sale of generation assets owned by an affiliate in order to open competition in areas where high levels of horizontal market power exist, such as in PS North.

Recommendation

Staff recommends that the Board direct staff to:

- Initiate and conduct a focused audit to look at the affiliate relations and market power issues raised in this proceeding or, alternatively, expand the scope of work of the ongoing comprehensive management audits to incorporate these issues through contract amendments;

- Submit to the Board by June 1, 2012 a draft request for proposals ("RFP") including a detailed scope for the focused audit or the expanded management audit;

- Review the draft RFP for a new pool of auditors to be presented to the Board early next year and ensure that the auditors possess the appropriate expertise to conduct the focused audit sought under this proceeding.

<u>Expansion of Affiliate Relations Rules</u>

The New Jersey Affiliate Relations Rules cover most of the ring-fencing standards dealing with the relationship between the electric public utility and the holding company, and between the electric public utility and the related competitive business segment. However, the Affiliate Relations Rules do not regulate the relationship between the holding company and the related competitive business segment or among the affiliates belonging to the competitive business segment (for example generation and supply) unless the electric public utility is involved or its financial viability is affected.

When voting in PJM high level committees, a holding company must choose one sector in which to cast its vote. Conversely, in lower committees individual voting is allowed without affiliate restrictions. Holding companies may strategize to get the maximum weight for their vote/s in the PJM stakeholder process without restrictions from FERC or PJM regarding the protection of electric public utility's interests directly, or the limitation of the weight the holding company can have on the utility's decision-making process.

Staff believes that the vote of an electric public utility regulated by the Board should not respond to interests foreign to its distribution business, much less be used to help its related competitive business segments gain competitive advantages through changes to the PJM Tariff and agreements. The PJM decision making process leading to PJM's MOPR Revisions Filing is a good example of how these types of affiliate relations need to be further reviewed by the Board.

Recommendation

Staff recommends that the Board direct Staff to initiate a stakeholder process to consider any revisions of the Board's Affiliate Relations Rules that may be needed to eliminate barriers to entry of new generation effected through involvement of the public utility, and submit specific recommendations to the Board within six months of the Board Order approving this Report.

2. Demand Response and Energy Efficiency Programs

Testimony presented at the June and October Hearings discuss the role of demand response and energy efficiency in contributing to meet resource adequacy requirements in PJM. Comverge and the NGO Commenters believe that the Board should employ a portfolio approach when investing ratepayers' money in new capacity resources and account for demand response and energy efficiency solutions to identified reliability needs. COMPETE and PJM point at demand response as a cheap capacity resource, which RPM has successfully fostered. Finally, LS Power claims that demand response is not a substitute for new generation.

New Jersey has actively supported energy efficiency initiatives and demand-side management programs for more than 20 years. Energy efficiency measures permanently reduce demand throughout the delivery year without any additional customer action or intervention. The Board has implemented a myriad of energy efficiency programs over the past few decades. The BPU's initiatives include home energy audits and rebate programs, which have resulted in the installation of more efficient appliances, equipment and devices, such as compact fluorescent bulbs and higher–efficiency kitchen appliances, as well as the replacement of inefficient heating and cooling systems. PJM currently recognizes the reliability value that energy efficiency measures provide, and such resources may participate in the RPM capacity market for up to four years after installation, as long as the energy-efficient equipment, devices, systems or processes remain operational.

To encourage customer demand response, the BPU has consistently directed utilities to implement demand-side management of energy consumption, primarily through utility-operated central air conditioning cycling ("AC Cycling") programs for residential customers. During 2008, PJM reported that ACE's zone provided 28 MW from all demand response resources; "JCP&L's zone provided 111.8 MW; PSE&G's zone provided 195.0 MW; and RECO's zone provided 2.2 MW, for a total of 337.0 MW of Installed Capacity ("ICAP") demand response. Demand response participation from all sources increased by 184.6 MW from December 2008 through December 2009. In 2009, PJM reported that participation in its load management programs resulted in 526.1 MW of ICAP demand response from consumers in New Jersey.

In 2009, the Board approved new AC Cycling Programs for PSE&G, JCP&L and ACE which promise to develop greater amounts of demand response within the State. At that time, the existing AC Cycling Program infrastructure was well beyond its expected lifetime, so the Board reaffirmed its commitment to demand response by approving investment in new equipment. Although the State's AC Cycling Programs are primarily directed at residential households, each utility program has a smaller segment offered to small commercial customers.

PSE&G's AC Cycling Program was designed to target approximately 17 percent of the utility's customer households that have central air conditioner units. The utility's AC Cycling Program effort comprises replacement of existing control devices and expansion to new program participants to reach a target of 168,300 residential customers with 181,764 control devices. The anticipated demand reduction from this new AC Cycling Program was projected at 130.9 MW annually by 2013, from a total investment projected to be $60.2 million from 2009 through 2013.

ACE's Residential Controllable Smart Thermostat Program ("RCSTP") is available to all residential customers with central air conditioners and/or heat pumps within ACE's service territory. The RCSTP is expected to include approximately 42,000 residential households with approximately 42,400 qualifying units. By year-end 2014, it is expected that the RCSTP will provide approximately 50.64 MW of demand response. The estimated total implementation cost of the program is $16.9 million.

Beginning in 2008, JCP&L implemented its Integrated Distributed Energy Resource ("IDER") Program. Initially designed as an 8 MW pilot, the IDER Program was expanded twice, to total approximately 38 MW upon completion of equipment installation. The IDER Program monitors non-critical customer electrical loads, in this case central air conditioners, with two-way communications and controls such equipment at an individual and at an aggregated level, by circuit, substation or other operational groupings.

In 2008, the Board also approved a modified version of a new program, proposed by a public advisory group, the Demand Response Working Group, that provided incentive payments to Curtailment Service Providers ("CSPs") who registered new and incremental capacity from commercial and industrial ("C&I") customers into PJM's Interruptible Load for Reliability ("ILR") demand response program for the period beginning June 1, 2009 through May 31, 2010. The Modified Demand Response Working Group Program provided a financial incentive in the form of a supplemental premium payment of $22.50 per megawatt-day to CSPs for new and incremental capacity, for the purpose of jump-starting competition in the demand response market in New Jersey.

Prior to the adoption of the Modified Demand Response Working Group Program, less than one percent of the State's summer electric demand was registered in PJM's demand response programs, and much of the existing demand response at that time came from the State's residential AC Cycling Programs. Beginning June 1, 2009, CSPs registered a total of 255 MW of new or incremental demand response from New Jersey's C&I customers, representing an increase of approximately 75 percent over the 337 MW previously registered in the program from that customer class. Approximately 90 percent of the new capacity that had participated in the Modified Demand Response Working Group Program registered for the following year in the period beginning June 1, 2010. Thus, the Modified Demand Response Working Group Program fulfilled its intended purpose to jump-start the competitive demand response market within the State.

Currently, the demand response from the State's AC Cycling Programs is bid into the PJM capacity auctions. Interestingly, FERC has not found that this state program unduly interferes with the RPM market. New Jersey has been successful in encouraging and developing customer demand response from all customer classes within the State.

Recommendation

Demand response and energy efficiency are capacity resources that can contribute to improved reliability in critical areas of New Jersey such as PS North. However, continuation of the reliability of the State's electric service requires a mix of resources, including new generation sources. Other than increased demand response resources, little capacity has been added to the state's electric infrastructure from other sources. Just as an RTO cannot rely solely on an increase in one type of resource to maintain system reliability, neither can a State rely only on demand response to ensure future reliability within its borders.

Staff believes that to date, RPM has been successful in attracting demand response and energy efficiency resources. Nevertheless, Staff recommends looking at ways of promoting increased demand response in strategic areas with critical reliability needs, so long as demand response does not threaten more permanent solutions such as entry of new generation resources.

3. Land for Building Generation

Testimony presented at the Board Technical Conference and the June and October Hearings indicate that the cost of land, restrictive land use permitting processes, and ownership by the incumbent generators and affiliated EDCs of many sites conducive to plant development, all constitute barriers to new generation entry in New Jersey.

Comverge and Exelon observed that complex permitting and land use restrictions limit the areas within which construction of new generation is appropriate, and frequently make the development of larger generation projects difficult. This is particularly true in densely settled areas of PJM like New Jersey. APPA argued that investment in generation does not happen in highly congested areas where LMP prices are the highest, partly because those investment decisions may be more dependent upon factors such as access to fuel, availability of land and labor, and the extent of likely local opposition.

Constellation Energy added that because of the higher costs of land and labor in New Jersey the state would benefit from lower cost of imported electricity as opposed to relying entirely on more expensive intrastate resources. Hess, on the other hand, points at the quantity and cost of land needed for transmission expansions as one of the reasons why generation might often be the economically favorable option.

The IMM testified that, to the extent that ownership of existing sites for generating units constitutes a barrier to entry for potential new entrants into the capacity market in New Jersey, the Board should consider its options under its regulatory jurisdiction for addressing that issue.

Land in Rate-base

The FERC Order accepting PSEG updated market power analysis and compliance filing under Dockets ER99-3151-008, ER97-837-007, ER03-327-002, ER08-447-000 and ER08-448-000, establishes that PSE&G has claimed to own certain sites that would be suitable for generating facilities but that under EDECA, PSE&G is effectively barred from owning and operating generation except "on-site" generation for supply of specific end-users. Similarly, other electric public utilities in New Jersey may own land that is suitable for building generation. Some or all of this land may be in rate base for one or more of the EDCs.

Recommendation

Eventually, each of the state's electric utilities will come to the Board for a rate case. In this context, Staff recommends looking at land owned by the electric and/or gas public utilities which may be suitable for building new generation and make recommendations as to whether these lands should continue in rate base.

4. State Power Authority

State power authorities ("SPAs") are generally government corporations that own generation or purchase electricity from other generators or suppliers, and market large quantities of electricity to groups of utilities, public power authorities, and companies within their states at potentially lower prices than the entities would otherwise pay. SPAs usually obtain their financing from state treasuries and from revenue bonds secured by proceeds from the sale of electricity.

Testimony presented at the June and October Hearings by Rate Counsel and the CCNJ support the establishment of a New Jersey Power Authority. The CCNJ believes that the Board should recognize the need to seize its own energy destiny and establish a SPA. According to the CCNJ, a SPA would increase reliability and spur economic development through the generation and sale of low cost power.

Rate Counsel recommends that the Board investigate the feasibility of the creation of a SPA in New Jersey to build new generation. The New Jersey SPA could be a state owned and operated organization with the authority to own and/or lease power generation and transmission facilities, sell power at wholesale and/or retail for certain types of customers, and enter into long-term contracts for the purchase of power and transmission capacity. The New York Power Authority ("NYPA") generates power from older plants (typically hydropower projects) at costs well below market prices. Unlike NYPA, a New Jersey SPA would need to either construct new generation resources or purchase existing generation resources at market value. Consequently, virtually all of the economic advantages associated with NYPA would not be available to a newly created New Jersey SPA. Notwithstanding this, the creation of a SPA in New Jersey could: (i) give the state the ability to construct generation on a schedule to match consumer demands for electric energy and at presumably lower costs than those borne by the private sector; and (ii) promote prices reflecting the actual costs to generate the power rather than market conditions that are currently administratively determined.

State Power Authorities across the United States

<u>The New York Public Power Authority</u>

NYPA is a New York State public benefit corporation and the largest state-owned power organization in the United States. It was created by the state legislature in 1931 to provide public ownership and control of the hydroelectric development of the St. Lawrence River. Today NYPA owns 17 generating resources and 1400 circuit miles of transmission assets.

NYPA is governed by a seven-member board of trustees who are appointed by the governor by and with the advice and consent of the senate. NYPA is a fiscally independent public corporation that does not receive state funds, tax revenues, or credits. The vast majority of NYPA projects are funded through the issuance of bonds financed predominantly through the sale of electricity.

NYPA generates, transmits, and sells electric power and energy. NYPA sells power to over 700 business and industrial customers, government agencies in New York City and Westchester County, the state's investor-owned utilities, the Long Island Power Authority, 47 municipally-owned utilities and four rural electric cooperatives in New York.

The Illinois Power Agency

The Illinois Power Agency ("IPA") was established in 2007 for the purposes of:

- Developing and submitting annual electricity procurement plans to the Illinois Commerce Commission ("ICC") that ensure adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time. The plans are to include electricity generated from renewable as well as clean coal resources.
- Conducting competitive procurement processes according to the procurement plans as approved by the ICC.
- Developing electric generation and co-generation facilities that use indigenous coal or renewable resources, or both, financed with bonds issued by the Illinois Finance Authority.
- Supply electricity at cost to municipal electric systems, governmental aggregators, or rural electric cooperatives in Illinois.

The IPA is self-funded through fees on utilities and the pricing of power. Generation construction is funded through revenue bonds issued by the state's Illinois Finance Authority ("IFA"). The maturity of the bonds must be no more than 40 years, and the bonds may be tax-exempt if the IPA determines that tax-exempt status is appropriate. The IPA has two bureaus, the Planning and Procurement Bureau and Resource Development Bureau. Both bureaus are headed directors appointed by the governor, subject to Senate approval.

The Arizona Power Authority

The Arizona Power Authority ("APA") was created by the Arizona legislature in 1944 for the purpose of acquiring and marketing the state's share of power produced by the Boulder Canyon Project. The APA, however, is not limited to these activities as it is empowered to acquire, construct, and operate necessary electric generation and transmission facilities. For this purpose, it may exercise the right of eminent domain and issue revenue bonds. By statute, the APA must be self-supporting and is prohibited from incurring any obligation that would be binding upon the State of Arizona.

The APA is governed by a five-member commission that is appointed by the Governor, subject to confirmation by the State Senate.

The Idaho Energy Resource Authority

The Idaho Energy Resource Authority ("IERA") was created in 2005 for the purpose of diversifying and expanding the state's economy through improvements in Idaho's electric generation and transmission infrastructure. This is to be achieved either by facilitating the development or expansion of electric facilities in Idaho or by allowing the import of low-cost energy from other parts of the region. Another purpose of the IERA is to promote the development of renewable energy resources.

The IERA shall pursue development of these facilities through joint agreements with participating utilities. A participating utility may include any electric utility (including cooperative and municipally owned systems) that serves customers in the state and any entity that provides wholesale power or transmission services to the state's electric utilities. The IERA can issue bonds and borrow money to achieve its purpose. Bonds may be secured by revenues of the IERA or by any part of the IERA's assets. Neither the state nor any agency or subdivision of the state is liable for repayment of these bonds. Once all bonds issued to finance the cost of a facility are paid off, the IERA will convey title of the facility to participating utilities.

The IERA is governed by seven directors appointed by the Governor and confirmed by the Senate, who serve five year terms.

Recommendation

If the SOCAs fail to clear the May 2012 and May 2013 BRAs, Staff recommends that the Board study the possibility of creating a New Jersey State Power Authority, which may be carried out independently or as part of an FRR initiative. Staff believes that this process should start with a stakeholder process to discuss the merits of establishing a SPA in New Jersey. Staff could develop a recommendation on this matter within a defined period of time to be established by the Board. Since EDECA places ultimate responsibility for procurement on the EDCs, legislation would be required if the BPU wishes to pursue this approach.

5. Fixed Resource Requirement Alternative

The FRR Alternative is a mechanism set forth in PJM's tariff for load serving entities to opt out of the RPM market and secure capacity to meet their load obligations free of the requirements of RPM. For purposes of the State of New Jersey, the FRR Alternative provides a last resort in efforts to secure adequate generation capacity resources should other efforts, including LCAPP, fail as a result of obstruction by PJM and FERC. The FRR Alternative was first publicly raised as an alternative to LCAPP by the IMM during testimony before the N.J. Legislature in December 2010.[70] Since that time, and especially as events have unfolded at FERC, Staff has investigated the feasibility of the FRR Alternative given the eventuality that the State may be unable to secure an exemption for LCAPP projects from the recently imposed minimum offer price rule. As

[70] http://www.monitoringanalytics.com/reports/Reports/2010/Bowring_NJ_Assembly_3442_Testimony_20121216.pdf

discussed above, imposition of the MOPR may effectuate a failure of the three executed SOCAs to clear the RPM auction, an essential ingredient in the LCAPP paradigm. The FRR Alternative stands as a final, albeit rigorous, means available to the State to secure its identified capacity needs outside of the reach of RPM requirements impeding these efforts.

In its MOPR Order determination to subject self-supply to MOPR provisions, FERC offered the FRR as an alternative to entities seeking to develop their own capacity supplies in a manner that, according to FERC, would not threaten the integrity of the RPM capacity market.[71] The Commission re-emphasized its opinion of the FRR Alternative in its Rehearing Order, indicating that while FRR may not be a viable substitute for many RPM participants, it remains a legitimate approach that "states and distribution companies can make…based on their individual circumstances." [72] The Commission referenced the core elements of the FRR Alternative, described in detail in the PJM Reliability Assurance Agreement, Schedule 8.1, as follows:

> An entity that chooses the FRR alternative submits an FRR capacity plan to PJM, a long-term plan for the commitment of capacity resources to satisfy the entity's capacity obligations. The area covered by the plan is: (i) the service territory of an investor-owned utility; (ii) the service area of a public power entity or electric cooperative; or (iii) a separately identifiable geographic area that is bounded by wholesale metering, or similar appropriate multi-site aggregate metering, and for which the FRR entity has or assumes the obligation to provide capacity for all load (including load growth) within such area.[73]

The essential elements of an FRR Alternative are composed of an FRR entity that has secured sufficient capacity to serve the entire load obligation within the FRR service area. An FRR service area is permissibly defined as a geographic area bounded by wholesale metering, transparent to the PJM Office of the Interconnection. Geographic areas bounded by wholesale metering observable by PJM include existing RPM locational deliverability areas ("LDAs"), which are currently bounded by such metering used in part to quantify both the load obligation of the area ("CETO") and the CETL into the area. By opting for the FRR Alternative, New Jersey would not be obligated to designate the entire State or even the entire geographic area comprising a zone. Rather, the State could designate a smaller portion of a zone corresponding to an existing RPM LDA.

The PS-NORTH LDA is a geographic area that is smaller than the entire PSEG zone, is bounded by wholesale metering transparent to PJM and is the subject of chronic reliability issues. PS-NORTH therefore represents the ideal FRR service area should the State choose to pursue the FRR option. Development of additional generation capacity resources within the PS-NORTH area would address the current problem of importing sufficient capacity due to transmission constraints while providing greater competition

[71] 135 FERC ¶ 61,022 at P 192-193 and 137 FERC ¶ 61,145 at P 160.

[72] 137 FERC ¶ 61,145 at P 100.

[73] Ibid. at P 160, n. 86.

and likely lower capacity prices over time. While PJM's FRR requirements specify that a substantial portion of capacity resources be located within PS-NORTH under a FRR scenario, anticipated DR and energy efficiency capacity resources, state facilitation of merchant generation within the LDA, and the potential for existing PSEG Power capacity to secure longer-term supply contracts would likely be sufficient to meet the minimum internal capacity obligation.[74] The balance of the load obligation could be met through imported capacity up to the identified CETL threshold.

The selection of an FRR entity to administer the FRR service area is relatively straight-forward. The State could enlist the existing EDC in whose territory the FRR service area is located; in the case of a PS-NORTH FRR service area, the FRR entity would be PSE&G. Alternately, the State could establish a public power entity, similar to the public power authorities existing in other states, for purposes of serving as the FRR entity; this is an option that would require statutory authority through new legislation. The FRR entity is responsible for ensuring that all load within the FRR service area, including load growth, is met with identified capacity resources. Initial designation of an FRR Alternative is for a minimum five year term with such selection made no later than two months prior to the BRA. No later than one month in advance of the BRA, the FRR entity must submit to PJM a detailed, resource-specific FRR capacity plan covering the designated term; annual updates of the capacity plan must be submitted each year through the commitment period. The capacity plan must demonstrate that adequate capacity resources have been secured to meet the FRR service area's daily unforced capacity obligation plus a specified reserve margin applicable to the zonal peak load forecast for each BRA delivery year.[75] While the capacity plan required under the RAA is rigorous, a conscientious approach to meeting its terms would render the FRR Alternative a viable one should efforts to develop NJ-based capacity, either through LCAPP or merchant development outside of LCAPP, fail to come to fruition. The FRR Alternative would vest significant latitude in the State for securing new generation capacity, outside of the existing impediments to those efforts evident in the RPM construct.

Recommendation

Staff recommends that the Board direct further investigation of establishing an FRR service area and FRR entity in a currently recognized RPM LDA, preferably the PS-NORTH LDA. Staff should work with PJM and potential capacity suppliers to determine the precise resource requirements of the selected FRR service area and identify the potential capacity resources needed to meet those requirements. Should the LCAPP units fail to clear the BRA and should insufficient levels of non-LCAPP merchant capacity clear the BRA, Staff recommends that the Board adopt the FRR Alternative as the principal mechanism to realize new generation capacity development in New Jersey. Implementation of this alternative would require legislation only If it is determined that a state power authority is the proper FRR entity to manage the FRR service area.

[74] http://www.pjm.com/markets-and-operations/rpm/rpm-auction-user-info.aspx#Item08 at 2014/2015 BRA Planning Period Parameters (XLS) tab. The 2014/2015 BRA planning parameters specify that 71.6 percent of capacity serving the FRR service area be located within its boundaries.

[75] PJM Reliability Assurance Agreement, Schedule 8.1, Sections C and D.

V. CONCLUSIONS

The deregulation of electricity markets in New Jersey and other states as well as across the globe has presented challenges to strike the balance between allowing markets to operate freely and providing the necessary regulatory oversight to ensure true competition. In the context of this balancing test, this Report has presented recent issues reflecting the current challenges for FERC, PJM and for New Jersey to promote new entry of generation.

After reviewing the testimony presented under the Board's capacity investigation procedures started in 2010, as well as filings and other documents presented under the LCAPP process, and the Federal and regional proceedings connected to the LCAPP process, Staff has provided the Board with the following recommendations with the ultimate goal of promoting greater reliability and competition through new generation entry:

- **Interconnection**. Staff recommends that the Board intervene and file comments with FERC regarding the PJM Tariff revisions to its interconnection process expected to be filed in February 2012. Additionally, the Board should support the queue break away proposal and the right of generators to use third party engineering consultants to perform interconnection studies.

- **MOPR**. Staff recommends that the Board: (i) continue to pursue the Board's MOPR Appeal filed on November 25, 2011 putting an emphasis on the FERC's rejection of the competitive, non-discriminatory auction proposal of the IMM; (ii) direct Staff to monitor the success of the three contracted SOCA projects in clearing the BRA under the revised MOPR rules in 2012 and 2013; (iii) if the SOCA projects fail to clear the BRA in 2012 and 2013, the Board should direct Staff to begin constructing an LCAPP II design contingency that incorporates a capacity procurement mechanism modeled on the aforementioned non-discriminatory, competitive auction proposal of the IMM, as modified by the Staff's market power mitigation feature, for use in contracting capacity for bid into the May 2014 BRA; and (iv) continue to monitor and, if necessary, engage in actions at FERC designed to ensure that the MOPR exception process is properly reflected in the PJM compliance filing .

- **RTEP**. Staff recommends that the Board: (i) file comments to the anticipated PJM February 2012 filing generally supporting the FYI process, but advising the Commission to be wary of potential negative impacts of introducing new decision frameworks in the RTEP on new generation entry; and (ii) file comments to the PJM December Filing.

- **NEPA**. Staff recommends that the Board not support a long-term auction process if it is open for existing resources and not solely to new entry.

- **FRR**. Staff recommends that the Board: (i) monitor the discussions at PJM regarding changes to the FRR rules and take an active role in promoting those changes necessary to facilitate an FRR alternative in New Jersey; (ii) file comments with FERC in support of those changes that facilitate the use of an FRR alternative in

New Jersey, should PJM file Tariff changes to the FRR rules; and (iii) direct Staff to conduct an investigation of the feasibility of establishing an FRR service area and a FRR entity in a currently recognized RPM LDA, preferably the PS-NORTH LDA.

- **Demand Response**. Staff recommends that the Board: (i) continue to actively monitor PJM's demand response reforms and the development of new demand response capacity products in order to maximize the State's demand response participation in the PJM markets; and (ii) direct Staff to look at ways of promoting demand response in strategic areas with critical reliability needs to the extent that such action do not preclude more permanent solutions such as new generation entry.

- **Affiliate Relations and Market Power.** Staff recommends that the Board direct Staff to: (i) initiate a focused audit to look at the affiliate relations and market power issues raised in this proceeding or, alternatively, expand the scope of work of the ongoing comprehensive management audits to incorporate these issues through contract amendments; (ii) submit to the Board by June 1, 2012, a draft RPF including a detailed scope for the focused audit or the expanded management audit; (iii) review the draft RFP for a new pool of auditors to be presented to the Board early next year and ensure that the auditors possess the appropriate expertise to conduct the focused audits sought under this proceeding; and (iv) initiate a stakeholder process investigating any needed changes to the Board's Affiliate Relations Rules and submit recommendations to the Board within six months of the Board Order approving this Report.

- **Land Suitable for Generation.** Staff recommends the Board direct Staff to examine the justification for land owned by the electric and/or gas distribution companies, which may be suitable for building new generation and to make recommendations as to whether these lands should continue in rate base.

- **State Power Authority**. Staff recommends that should the Board decide to proceed in exploring the SPA alternative, the Board: (i) direct Staff to initiate a stakeholder process to discuss the merits of establishing a SPA in New Jersey; and (ii) direct Staff to develop a recommendation on this matter, including recommendations for any needed legislation, within a defined period of time to be established by the Board.