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BEFORE THE NEW JERSEY BOARD OF PUBLIC UTILITIES

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Investigation of Resource Adequacy Alternatives	)	**Docket No. EO20030203**
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Pursuant to the Order issued in this proceeding effective March 27, 2020, and the Request for Written Comments issued in this proceeding March 27, 2020, Monitoring Analytics, LLC, acting in its capacity as the Independent Market Monitor for PJM[1] ("Market Monitor"), submits these comments. The Market Monitor also attaches a report analyzing the impacts on capacity prices for New Jersey ratepayers that would result from the State of New Jersey participating in a statewide Fixed Resource Requirement ("FRR") Plan.[2]

I. COMMENTS

A. Responses to Comments Solicited by the Board.

The topics identified by Staff and the Market Monitor's responses:

1. Can New Jersey Utilize the Fixed Resource Requirement ("FRR") Alternative to Satisfy the State's Resource Adequacy Needs?

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[1] Capitalized terms used herein and not otherwise defined have the meaning used in the PJM Open Access Transmission Tariff ("OATT"), the PJM Operating Agreement ("OA") or the PJM Reliability Assurance Agreement ("RAA").

[2] *See* Attachment, which can also be accessed at: <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of_New_Jersey_FRRS_20200513.pdf>; RAA Schedule 8.1 § I.

While there is a wide range of ways in which New Jersey could meet its reliability needs, including a return to cost of service regulation, signing long term contracts with individual suppliers, creating an FRR, or creating a power authority, the Market Monitor recommends that New Jersey consider which is the least cost, most efficient and most effective way to meet New Jersey's reliability needs in the short run and in the long run. Despite the imperfections in the capacity market that the Market Monitor has repeatedly documented, competitive markets continue to be the standard against which any of the long list of nonmarket solutions must be measured.

a. Discussion of the FRR requirements under the PJM Tariff and how they may be applied to a restructured state, New Jersey specifically.

   Please see the IMM's attached report: Potential Impacts of the Creation of New Jersey FRRs, pp. 4–6; 18–20.

b. Discussion of any practical limits presented as a result of New Jersey's geographic location along the Atlantic Ocean and along the NYISO Seam.

   The Market Monitor has no comment at this time.

c. Discussion of the pricing and/or rate implications associated with FRR.

   Please see the IMM's attached report: Potential Impacts of the Creation of New Jersey FRRs, pp. 1–4; 20–40.

d. Discussion of whether and how the State could pursue an FRR construct under existing legislative and regulatory provisions.

   Please see the IMM's attached report: Potential Impacts of the Creation of New Jersey FRRs, pp. 4–6; 18–20.

e. Discussion of any New Jersey legislative and regulatory limitations or potential amendments necessary to pursue FRR.

   The Market Monitor has no comment at this time.

f. Discussion of which entity would procure capacity under an FRR construct and whether capacity would be procured state-wide.

   Please see the IMM's attached report: Potential Impacts of the Creation of New Jersey FRRs, pp. 5–6.

g. Discuss the pros and cons of a State Power Authority ("SPA"), looking at examples from across the country, including discussion of any legislative and regulatory limitations and potential amendments necessary to pursue an SPA.

h. It is not clear why adding a centralized purchasing authority to replace the individual decisions of customers in the power markets would enhance efficiency, competitiveness or effectiveness compared to current market outcomes, with or without need modifications to the current market design. Discussion of any affiliate relations or market power concerns related to implementation of FRR in New Jersey.

   Please see the IMM's attached report: Potential Impacts of the Creation of New Jersey FRRs, pp. 8–11. The FRR construct raises serious issues of market power in New Jersey.

i. Discussion of any related topics.

   Please see Section B.

2. Can New Jersey Utilize the FRR to Accelerate Achievement of New Jersey Clean Energy Goals?

   a. Discuss whether FRR is a viable construct to assist New Jersey in achieving its clean energy goals.

      FRR is a nonmarket approach. There is nothing inherent in the FRR approach that gives New Jersey special assistance in pursuing clean energy goals.

b. Discuss whether any FRR could be structured to ensure procurement of clean energy resources to meet resource adequacy needs in line with the 2019 EMP objectives.

The Market Monitor's responses to these questions all assume that New Jersey's goal is to meet its reliability and environmental goals in a cost effective manner so as to define the objectives clearly and to minimize the costs to customers of reaching the defined objectives. It has been demonstrated repeatedly in New Jersey and elsewhere that long term, guaranteed contracts are generally not a good method for purchasing power, regardless of its characteristics, in a cost effective manner. Reliance on markets, subject to oversight, regulation and good market design, is preferable to relying on FRR type constructs which are nonmarket, planned approaches that rely on the judgment of planners rather than on providing incentives to market participants and shifting risk from customers to market participants. To the extent that FRR constructs provide incentives to planners to enter into long term contracts, the FRR approach will shift risks from investors to customers, which is an inefficient and ineffective and costly design.

i. How would procuring greater numbers of clean energy resources affect pricing outcomes?

As a result of the fact that the FRR is a nonmarket approach, it is not clear what is meant by pricing outcomes. To the extent that clean energy resources are competitive now and are expected to be even more competitive in the next few years, the increase in renewable resources will be a function of investors' willingness to follow market incentives, supplemented in some cases by RECs and SRECs. Regardless of whether markets continue to be relied on or there is a switch to FRR, the marginal reliability value of clean resources will decline as the MW of nameplate capacity of clean resources increase. In order to meet significant clean energy targets with intermittent resources, overbuilding is required. One result will be that some clean energy resources will need to be turned off during times of maximum clean energy production. The total nameplate capacity (and the capacity to produce energy under ideal conditions) of intermittent resources required to be reliable is, by definition, well in excess of peak loads.

ii. Could the State require that procurements "internalize" the value of anticipated carbon emissions during the delivery year, subject to a true-up?

The best way to internalize the cost of carbon emissions is through a carbon price, like RGGI. The impact of the RGGI price would be increased if the RGGI price were closer to the social cost of carbon, and if more states joined RGGI. Membership in RGGI by PJM states would be more likely to receive a thorough review from all PJM states if PJM provided detailed information about the results of their carbon price analysis, including: impacts on the net revenues of individual units; impacts on the carbon price revenues that would flow to each state; impacts on LMP by zone and time period. States could make rational decisions and rational compromises about carbon pricing if more information were provided to them.

iii. How could New Jersey determine what such a reference carbon value could be, addressing both price and environmental considerations?

The social cost of carbon has been studied extensively. The choice about which price level to actually implement is a policy choice which would reasonably reflect the tradeoff between energy prices, offset by the return of carbon price revenues, and the associated reduction in carbon emissions. But it is essential that New Jersey have an internally consistent view of the appropriate reference carbon price. New Jersey policy currently reflects an incredibly wide divergence in the value of carbon across its applications in New Jersey energy policy.

iv. How would preferentially procuring clean energy resources affect reliability outcomes?

Please see response to 2.b.i.

c. Discuss whether the State should consider adopting an energy market carbon dispatch price, in addition to RGGI, in lieu of an FRR approach.

i. How would such an approach work?

There is no reason to use an energy market carbon dispatch price in addition to RGGI. There are direct ways to make RGGI more effective.

ii. Discuss whether such a carbon price is a viable construct to ultimately get New Jersey to achieve the totality of the 2019 EMP goals.

RGGI is a viable construct which could be strengthened in identifiable ways.

d. Discuss whether there are any other models for meeting the state's resource adequacy needs and advancing the state's clean energy agenda.

A non-FRR model is continued reliance on the PJM capacity market with significant reforms to that market plus additional incentives as needed. Those reforms include addressing market power, the over forecasting of demand and the associated over procurement of capacity.

3. Can Modifications to the Board's Basic Generation Service Construct Facilitate Resource Adequacy Procurements aligned with the EMP Clean Energy Objectives?

Given the current issues raised by the April 26, 2020, FERC order (171 FERC ¶ 61,035 at P 386) related to the potential use of the BGS auction and similar auctions to advance state planning objectives, the Market Monitor recommends not attempting to use the BGS to implement state energy policy in favor of particular resources. The FERC has made clear that they consider such designs to be state subsidies subject to the Minimum Offer Price Rule ("MOPR"). Retail auctions serve the key function of providing retail electric service at competitive prices to a wide range of customers. If RGGI were used as an effective carbon pricing mechanism and New Jersey instituted a consistent approach to pricing carbon emissions, there would be no reason to modify the design of the BGS auction to implement clean energy policy.

a. Discussion of a portfolio manager approach as a means of providing for a wider range of resource options.

   The Market Monitor has no comment at this time. Please also see the response to A.1.h.

b. Discuss potential changes to the BGS competitive processes to facilitate procurement of resources that meet the State's long-term clean energy objectives. Discuss efficiency implications of each option.

   i. Clean Energy Standard, utilizing certificates to demonstrate compliance.

      Please see the response to 3.

   ii. Obligations on BGS Bidders to procure clean capacity resources, potentially with locational requirements.

      Please see the response to 3.

   iii. Billing capacity obligations to BGS Bidders from a state FRR portfolio.

      Please see the response to 3.

   iv. Other potential BGS construct modifications to meet the state's resource adequacy needs and advancing the state's clean energy agenda.

Please see the response to 3.

c. Discussion of the pros and cons of modifying the BGS construct to facilitate the State's long-term clean energy objectives.

d. Please see the response to 3.Discussion of legislative and regulatory limitations and potential amendments necessary to enable the BGS construct to effectively facilitate the State's long term clean energy objectives, through the options recommended above or other options presented.

   Please see the response to 3.

e. Discussion of affiliate relations or market power concerns related to any proposed changes to the BGS construct.

   Please see the response to 3.

f. Discussion of whether the BGS construct can ultimately get New Jersey to achieve the totality of the 2019 EMP goals.

   Please see the response to 3.

g. Discussion of any additional related topics.

   Please see Section B.

4. Can Other Mechanisms, such as a Clean Energy Standard or Clean Energy Market, Facilitate Achievement of New Jersey Clean Energy Goals?

   To the extent that reducing carbon emissions is the key goal of New Jersey's clean energy goals, an essential first step is establishing New Jersey's definition of the social cost of carbon. At present New Jersey does not value carbon emissions in a consistent way. The implied cost of carbon in New Jersey REC prices is $18.11/tonne.[3] The implied cost of carbon in New Jersey's SREC prices is

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[3] *See* Table 8-7, "2020 Quarterly State of the Market Report: January through March," Monitoring Analytics, LLC, p. 361 <http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2020.shtml>.

$364.33/tonne.[4] The RGGI price of carbon is $6.23/tonne.[5] The mechanisms for implementing a rational carbon policy are available to New Jersey without inventing another complex way to address the carbon issue. First establishing a clear and consistent approach to the cost of carbon for New Jersey is essential to an efficient and cost-effective approach to limiting carbon. Coordinating with other PJM and even non-PJM states on a common approach to valuing carbon emissions and permitting trading of RECs and SRECs across state borders would be another step that could be taken without inventing a complex new administrative approach to addressing the carbon issue. New Jersey should also make an explicit decision about how much New Jersey residents should pay to address carbon in light of the fact that carbon is a global and not a local issue and that there is a potential for New Jersey to disadvantage its own competitive position by acting unilaterally rather than in coordination with other PJM and neighboring states.

The value of carbon emissions can also inform the level of New Jersey activity in the direct regulation of the efficiency of both residential and commercial buildings; vehicles; lighting; and appliances. The value of carbon emissions could also inform New Jersey decisions about whether extending a carbon price to sectors other than centralized energy production would be effective.

a. Discussion of alternative competitive processes to facilitate the State's long-term clean energy objectives.

   Please see response to 1, 2, 3, and 4.

b. Discussion of implementation of a Clean Energy Standard.

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4 *Id*.

5 *Id*.

Please see response to 4.

c. Discussion of the pros and cons of various alternative market constructs to achieve a clean energy future.

   Please see response to 1, 2, 3 and 4.

d. Discussion of legislative and regulatory limitations and potential amendments necessary to advance alternative market mechanisms to achieve the 2019 EMP goals.

   The Market Monitor has no comment at this time.

e. Discussion of affiliate relations or market power concern related to proposed alternative mechanisms.

   One of the reasons to rely on competitive markets is to ensure competitive outcomes, not affected by market power in any form. Creating and sustaining markets with broad and unlimited participation by resources that are full substitutes is essential to limiting market power. In addition, markets require explicit rules in order to prevent the exercise of market power. One of the key reforms required in the PJM capacity market design right now is to reduce the market seller offer cap to a competitive level. New Jersey customers should not have to pay capacity prices inflated by market power or affected by over forecasting of demand and the associated over procurement of capacity.

B. Additional Comments

The Market Monitor appreciates the opportunity to provide analysis and comments to the New Jersey Board of Public Utilities as it considers the critical issues associated with the design of capacity and energy markets and their intersection with environmental policy. The Market Monitor continues to recommend that the Board consider the benefits that PJM markets have brought and will continue to bring to New Jersey and how markets could be improved to enhance those benefits.

II. CONCLUSION

The Market Monitor respectfully requests that the Commission afford due consideration to these comments as it determines how to best ensure resource adequacy in New Jersey.

Respectfully submitted,

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Dated: May 20, 2020

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Eagleville, Pennsylvania,
this 20th day of May, 2020.

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Attachment

Potential Impacts of the Creation of New Jersey FRRs

The Independent Market Monitor for PJM

May 13, 2020

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Summary

The Independent Market Monitor for PJM (IMM or MMU) analyzed the impacts of the creation of Fixed Resource Requirement (FRR) entities in New Jersey. FRR entities elect to not participate in the PJM Capacity Market and to use the FRR option to satisfy their capacity obligations. Under the FRR option, Load Serving Entities (LSEs) in New Jersey would need to meet their FRR capacity obligations through owned generation, if any, and bilateral contracts with the owners of capacity, primarily within the AECO, JCPL, PSEG and RECO Zones but also including resources from outside New Jersey. The IMM analyzed six scenarios. Separate Locational Deliverability Areas (LDAs) for AECO and RECO were not analyzed because of their relatively small load obligations. The load obligation of AECO and RECO together only accounts for 15 percent of the total load obligation of New Jersey.

All four zones in New Jersey are entirely within New Jersey. The PSEG Zone includes the PSEG North LDA, the Rest of PSEG LDA and the PSEG portion of the Rest of EMAAC LDA, all of which are part of the EMAAC parent LDA. The AECO Zone, JCPL Zone and RECO Zone are not modeled LDAs and are part of the Rest of EMAAC LDA.

In Scenario 1, the IMM assumes that an FRR is established that includes all of New Jersey and that the FRR procures the entire New Jersey capacity obligation at a rate equal to the weighted average net Cost of New Entry (CONE) times B offer caps applicable to the LDAs in New Jersey ($235.42 per MW-day) for the 2021/2022 PJM Reliability Pricing Model (RPM) Base Residual Auction (BRA). The IMM concludes that under Scenario 1, net load charges for New Jersey under the FRR alternative would increase by $386.4 million or 29.6 percent compared to the results of the 2021/2022 RPM BRA.

In Scenario 2, the IMM assumes that an FRR is established that includes all of New Jersey and that the FRR procures the entire New Jersey capacity obligation at a rate equal to the weighted average clearing prices in the 2021/2022 RPM BRA applicable to the LDAs in New Jersey ($186.16 per MW-day). The IMM concludes that under Scenario 2, the net load charges for New Jersey under the FRR alternative would increase by $32.0 million or 2.4 percent compared to the results of the 2021/2022 RPM BRA.

For both Scenarios 1 and 2, the IMM also analyzed the impacts on the RTO, excluding New Jersey. In both scenarios, the Rest of RTO clearing price would decrease by $12.61 per MW-day to $127.39 per MW-day, or 9.0 percent compared to the results of the 2021/2022 RPM BRA. In both scenarios, the EMAAC clearing price would decrease by $38.34 per MW-day to $127.39 per MW-day, or 23.1 percent. In both scenarios, the ComEd clearing price would decrease by $6.54 per MW-day to $189.01 per MW-day, or 3.3 percent. In both scenarios, the DEOK clearing price would decrease by $11.53 per MW-day to $128.47 per MW-day, or 8.2 percent. Net load charges for the RTO excluding New Jersey would be lower by $783.9 million or 9.7 percent compared to the 2021/2022 RPM BRA net load charges.

In Scenario 3, the IMM assumes that an FRR is established for the PSEG LDA (PSEG FRR) and that the FRR procures the entire PSEG capacity obligation at a rate equal to the 2021/2022 net CONE times B offer cap for PSEG ($244.24 per MW-day). The rest of New Jersey remains in the PJM Capacity Market. The IMM concludes that under Scenario 3 net load charges for PSEG under the FRR alternative would increase by $199.0 million or 27.2 percent compared to the results of the 2021/2022 RPM BRA.

In Scenario 4, the IMM assumes that an FRR is established for the PSEG LDA and that the FRR procures the entire PSEG capacity obligation at a rate equal to the clearing price in the 2021/2022 RPM BRA ($204.29 per MW-day). The IMM concludes that under Scenario 4 the net load charges for PSEG under the FRR alternative would increase by $46.6 million or 6.4 percent compared the results of the 2021/2022 RPM BRA.

For both Scenarios 3 and 4, the IMM also analyzed the impacts on the RTO, excluding the PSEG FRR. In both scenarios, the Rest of RTO clearing price would decrease by $31.27 per MW-day to $108.73 per MW-day, or 22.3 percent compared to the results of the 2021/2022 RPM BRA. In both scenarios, the EMAAC clearing price would decrease by $10.73 per MW-day to $155.00 per MW-day, or 6.5 percent. In both scenarios, the DEOK clearing price would decrease by $11.53 per MW-day to $128.47 per MW-day, or 8.2 percent. The clearing price in all New Jersey LDAs other than PSEG would decrease. Net load charges for the RTO excluding the PSEG FRR would be lower by $1,144.3 million or 13.2 percent compared to the 2021/2022 RPM BRA net load charges.

For both Scenarios 3 and 4, the IMM also analyzed the net impact on New Jersey. In both Scenarios 3 and 4, the net load charges for New Jersey, excluding the PSEG FRR, would decrease by $42.3 million or 7.3 percent compared to the results of the 2021/2022 RPM BRA. In Scenario 3, the net load charges for all New Jersey, including the PSEG FRR, would increase by $156.7 million or 12.0 percent compared to the results of the 2021/2022 RPM BRA. In Scenario 4, the net load charges for all New Jersey, including the PSEG FRR, would increase by $4.4 million or 0.3 percent compared to the results of the 2021/2022 RPM BRA.

In Scenario 5, the IMM assumes that an FRR is established for the JCPL LDA (JCPL FRR) and that the JCPL FRR procures the entire JCPL FRR capacity obligation at a rate equal to the 2021/2022 net CONE times B offer cap for JCPL ($217.38 per MW-day). The rest of New Jersey remains in the PJM Capacity Market. The IMM concludes that under Scenario 5, net load charges for the JCPL FRR under the FRR alternative would increase by $110.3 million or 28.3 percent compared to the results of the 2021/2022 RPM BRA.

In Scenario 6, the IMM assumes that an FRR is established for the JCPL LDA and that the JCPL FRR procures the entire JCPL capacity obligation at a rate equal to the clearing price in the 2021/2022 RPM BRA ($165.73 per MW-day). The IMM concludes that under Scenario 6 the net load charges for the JCPL FRR under the FRR alternative would decrease by $8.4 million or 2.1 percent compared the results of the 2021/2022 RPM BRA.

For both Scenarios 5 and 6, the IMM also analyzed the impacts on the RTO, excluding the JCPL FRR. In Scenario 5, the Rest of RTO clearing price would decrease by $18.31 per MW-day to $121.69 per MW-day, or 13.1 percent compared to the results of the 2021/2022 RPM BRA. The EMAAC clearing price would increase by $8.81 per MW-day to $174.54 per MW-day, or 5.3 percent compared to the results of the 2021/2022 RPM BRA. The PSEG clearing price would increase by $24.68 per MW-day or 12.1 percent compared to the results of the 2021/2022 RPM BRA. The DEOK clearing price would decrease by $11.53 per MW-day to $128.47 per MW-day, or 8.2 percent. In Scenario 5, the net load charges for the RTO excluding the JCPL LDA would be lower by $518.7 million or 5.8 percent compared to the 2021/2022 RPM BRA net load charges.

In Scenario 6, the Rest of RTO clearing price would decrease by $16.39 per MW-day or 11.7 percent compared to the results of the 2021/2022 RPM BRA. The EMAAC clearing price would increase by $19.27 per MW-day to $185.00 per MW-day or 11.6 percent compared to the results of the 2021/2022 RPM BRA. The DEOK clearing price would decrease by $11.53 per MW-day to $128.47 per MW-day, or 8.2 percent. In Scenario 6, the net load charges for the RTO excluding the JCPL LDA would be lower by $433.3 million or 4.8 percent compared to the 2021/2022 RPM BRA net load charges.

For both Scenarios 5 and 6, the IMM also analyzed the impact on New Jersey. In Scenario 5, the net load charges for New Jersey, excluding the JCPL FRR, would increase by $63.5 million or 6.9 percent compared to the results of the 2021/2022 RPM BRA. In Scenario 5, the net load charges for all New Jersey, including the JCPL FRR, would increase by $173.8 million or 13.3 percent compared to the results of the 2021/2022 RPM BRA.

In Scenario 6, the net load charges for New Jersey, excluding the JCPL FRR, would increase by $37.1 million or 4.0 percent compared to the results of the 2021/2022 RPM BRA. In Scenario 6, the net load charges for all New Jersey, including the JCPL FRR, would increase by $28.8 million or 2.2 percent compared to the results of the 2021/2022 RPM BRA.

Table 1 presents a summary of the results for all six scenarios including the impact on net load charges: for the defined FRRs; for New Jersey excluding the defined FRRs; for all of New Jersey including the defined FRRs and the non FRR portions of New Jersey; and for the rest of the PJM market, where the rest of the PJM market includes the non FRR portions of New Jersey when relevant.

Table 1 Scenario summary

Scenario	FRR Change	FRR Percent	Rest of New Jersey Change	Rest of New Jersey Percent	New Jersey Change	New Jersey Percent	Rest of PJM Market Change	Rest of PJM Market Percent
1	$386,448,104	29.6%	NA	NA	$386,448,104	29.6%	($783,926,664)	(9.7%)
2	$31,972,755	2.4%	NA	NA	$31,972,755	2.4%	($783,926,664)	(9.7%)
3	$198,950,988	27.2%	($42,257,383)	(7.3%)	$156,693,605	12.0%	($1,144,282,356)	(13.2%)
4	$46,635,898	6.4%	($42,257,383)	(7.3%)	$4,378,515	0.3%	($1,144,282,356)	(13.2%)
5	$110,330,027	28.3%	$63,456,528	6.9%	$173,786,555	13.3%	($518,687,090)	(5.8%)
6	($8,362,231)	(2.1%)	$37,134,318	4.0%	$28,772,087	2.2%	($433,329,584)	(4.8%)

Based on the analysis, the creation of a New Jersey FRR, a PSEG FRR or a JCPL FRR, is likely to increase payments for capacity by customers in New Jersey. It is expected that the actual price for capacity in New Jersey would be the result of a negotiation between the owners of the required capacity, and the State of New Jersey.[1] The price for capacity resources could substantially exceed the capacity market clearing price and the capacity market offer cap.

Creation of an FRR creates market power for the small number of local generation owners from whom generation must be purchased in order to meet the reliability requirements of the FRR entities. All participants in the New Jersey, JCPL, and PSEG FRRs fail the one and three pivotal supplier test which reinforces the conclusion that there is structural market power in each case. A fundamental point about the FRR approach is that the FRR approach is a nonmarket approach. In the FRR approach, there is no PJM market monitoring of offer behavior by generation owners, there are no market rules governing offers, and there are no market rules requiring competitive behavior. In the absence of a competitive market that includes the FRR area(s), there is no competitive market reference point to define what a competitive offer would be from the FRR generation owners in a bilateral negotiation or what the competitive market price would be. Prior market results do not define a competitive outcome in subsequent periods because market dynamics and market outcomes may change significantly. As a result, even the higher estimates of the cost impact to the customers of New Jersey from the creation of an FRR are likely to be conservatively low. If New Jersey were to subsidize any generating units, the subsidy costs would be in addition to the direct FRR costs.

Introduction

In this report, the IMM analyzes the rules governing the FRR alternative to direct participation in the PJM Capacity Market and a range of potential impacts of creating a New Jersey FRR service area both on payments by customers in New Jersey and by

1 This could also include the owners of capacity that could be imported, limited by the CETL.

customers in the balance of the RTO, based on explicitly stated assumptions.[2] The IMM previously published reports on the impacts of a ComEd FRR and of a set of Maryland FRRs but the public discussion of potential FRRs in other LDAs has not been supported by analysis to date.[3] [4] The IMM will provide analyses of the outcomes under different assumptions and of other potential FRRs, upon request. The IMM previously provided comparable analysis of FERC's resource specific FRR approach and of PJM's extended resource carve out proposal or repricing approach.[5] The IMM also provided an analysis of the impact of the MOPR order on prices in the upcoming BRA.[6]

The American Electric Power Company, Inc. (AEP) created the first FRR service area based on the original RPM tariff rules implemented in 2007.[7] AEP was a vertically integrated utility (transmission, generation and distribution assets) which participated in all the other PJM markets, but which, rather than participating in the PJM Capacity Market, received payment for generation capacity well in excess of capacity market prices, based on a cost of service model, under a regulatory arrangement with Ohio.

In order to create a new FRR service area, a utility (investor owned, electric cooperative or public power entity) must elect the FRR option consistent with the PJM Market Rules. The utility can make a voluntary FRR election or be required to make the FRR election by the state in which the FRR exists.

There are four transmission zones in New Jersey: Atlantic Electric Company (AECO), Jersey Central Power and Light Company (JCPL), Public Service Electric and Gas Company (PSEG), and Rockland Electric Company (RECO). New Jersey could require that all LSEs located in the state elect FRR status or that all LSEs in specific zones elect

2 See Reliability Assurance Agreement Among Load Serving Entities in the PJM Region ("RAA"), Article 1 and Schedule 8.1.

3 "Potential Impacts of the Creation of a ComEd FRR," Monitoring Analytics, LLC, <http://www.monitoringanalytics.com/reports/Reports/2019.shtml> (December 18, 2019).

4 "Potential Impacts of the Creation of Maryland FRRs," Monitoring Analytics, LLC, <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of_Maryland_FRRs_20200416.pdf> (April 16, 2020).

5 See Monitoring Analytics, LLC "MOPR/FRR Sensitivity Analyses of the 2021/2022 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2018/IMM_MOPR_FRR_Sensitivity_Analyses_Report_20180926.pdf> (September 26, 2018).

6 See Monitoring Analytics, LLC "Potential Impacts of the MOPR Order," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_MOPR_Order_20200320.pdf> (March 20, 2020).

7 See RAA Schedule 8.1; 117 FERC ¶ 61,331 (2006) at PP 36, 113.

FRR status.[8] Regardless of the existence of retail choice, the FRR entity must include all load in the FRR service area and must provide adequate capacity to meet that load. In the AEP case, AEP owned enough generation assets to meet its PJM defined UCAP obligation. In New Jersey, there are not enough capacity resources to meet the PJM defined FRR UCAP obligation. In order to create a viable New Jersey FRR, LSEs in New Jersey would need to contract with other capacity resource owners in New Jersey, and capacity resource owners external to New Jersey, limited by Capacity Emergency Transfer Limit (CETL) and minimum internal resource requirement, to meet the FRR UCAP obligation for the load in New Jersey.[9] There are shortfalls in internal capacity for a New Jersey FRR, a PSEG FRR and a JCPL FRR.

The analysis in this report is based on the actual auction inputs and results for the PJM Reliability Pricing Model (RPM) BRA (BRA) for the 2021/2022 Delivery Year, the last BRA run.[10]

The IMM evaluated the results of creating a New Jersey FRR service area for load in New Jersey, and for the rest of the capacity market, under six scenarios:

- Scenario 1: An FRR is established that includes all of New Jersey and the FRR procures the entire New Jersey capacity obligation at a rate equal to the weighted average of the 2021/2022 net CONE times B offer caps applicable to the LDAs in New Jersey ($235.42 per MW-day).
- Scenario 2: An FRR is established that includes all of New Jersey and the FRR procures the entire New Jersey capacity obligation at a rate equal to the weighted

8 An FRR entity is required to meet the capacity obligations of all alternative retail LSEs in the FRR service area. The alternative retail LSEs are required to compensate the FRR entity based on a state mandated compensation mechanism or based on the Rest of RTO capacity price, in the absence of a state compensation mechanism. For any delivery year subsequent to those addressed in the FRR entity's current FRR capacity plan, the alternative retail LSE may satisfy the load payment to the FRR entity with capacity resources.

9 The minimum internal resource requirement is the minimum percentage of capacity resources that must be located within an LDA to satisfy an FRR plan. It is calculated as the LDA reliability requirement minus CETL, divided by the zonal peak load forecast times the forecast pool wide requirement for the delivery year. In the 2021/2022 RPM BRA, PSEG and PSEG North LDAs did not have defined minimum internal resource requirements.

10 Participant behavior and market performance were evaluated as not competitive in the 2021/2022 RPM Base Residual Auction. See Monitoring Analytics, LLC, "Analysis of the 2021/2022 RPM Base Residual Auction - Revised," <http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Analysis_of_the_20212022_RPM_BRA_Revised_20180824.pdf> (August 24, 2018).

average clearing prices in the 2021/2022 RPM BRA applicable to LDAs in New Jersey ($186.16 per MW-day).

- Scenario 3: An FRR is established for the PSEG LDA and the FRR procures the entire PSEG capacity obligation at a rate equal to the 2021/2022 net CONE times B offer cap for PSEG ($244.24 per MW-day).
- Scenario 4: An FRR is established for the PSEG LDA and the FRR procures the entire PSEG capacity obligation at a rate equal to the PSEG clearing price in the 2021/2022 RPM BRA ($204.29 per MW-day).
- Scenario 5: An FRR is established for the JCPL Zone and the FRR procures the entire JCPL capacity obligation at a rate equal to the 2021/2022 net CONE times B offer cap for JCPL ($217.38 per MW-day).
- Scenario 6: An FRR is established for the JCPL Zone and the FRR procures the entire JCPL capacity obligation at a rate equal to the clearing price applicable to the JCPL Zone in the 2021/2022 RPM BRA ($165.73 per MW-day).

Assumptions

1. In Scenarios 1 and 2, the PJM Capacity Market would not include New Jersey. In Scenarios 3 and 4, the PJM Capacity Market would not include the PSEG LDA. In Scenarios 5 and 6, the PJM Capacity Market would not include the JCPL LDA.
2. In Scenarios 1 and 2, the FRR service area would include all of New Jersey. In Scenarios 3 and 4, the FRR service area would include the PSEG LDA. In Scenarios 5 and 6, the FRR service area would include the JCPL LDA.
3. There would be capacity imports into New Jersey FRRs only from capacity resources needed to cover any shortfall in meeting the FRR obligation. The price of imports to New Jersey from capacity resources outside New Jersey is assumed to be the same as the price paid to the capacity resources in New Jersey meeting the FRR obligation.
4. All capacity resources would be eligible to meet FRR reliability requirements. This includes matched seasonal resources with an annual equivalent offer price less than or equal to the rate paid to all annual capacity resources in the FRR service area.
5. Unmatched seasonal resources would offer their capacity in the PJM Capacity Market. These resources would be mapped to the relevant parent LDA. In the 2021/2022 BRA, less than 50 annual equivalent ICAP MW, or less than 0.3 percent of the New Jersey FRR obligation, were offered as seasonal capacity.
6. All resources that do not enter a contract with a New Jersey FRR would offer their capacity resources in the PJM Capacity Market.
7. The MW capacity of energy efficiency resources that are part of the FRR plan would be added back to the FRR obligation.[11]

[11] The FRR obligation is based on the PJM peak load forecast for the delivery year. The PJM peak load forecast accounts for the contribution of energy efficiency resources to reducing

Market Structure

Table 2 shows the New Jersey generation capacity resources in terms of installed capacity (ICAP).

Table 2 Generation capacity resources by transmission zone in New Jersey

Zone	ICAP (MW)	Percent
AECO	1,865.2	12.8%
JCPL	3,625.3	24.8%
PSEG	9,098.6	62.4%
RECO	0.0	0.0%
Total	14,589.1	100.0%

Table 3 shows the installed capacity by fuel source for the capacity resources located in New Jersey.[12]

Table 3 Installed capacity by fuel source[13] [14]

Modeled LDA	Zone	Coal	Gas	Nuclear	Oil	Solar	Solid Waste	Hydroelectric	Wind	DR	EE	PRD	Total
Rest of EMAAC	AECO	458.9	1,371.1	0.0	22.9	12.3	0.0	0.0	0.0	76.8	35.8	0.0	1,977.8
Rest of EMAAC	JCPL	0.0	3,020.0	0.0	216.1	58.1	10.0	321.1	0.0	156.6	161.4	0.0	3,943.3
Rest of EMAAC	PSEG	0.0	0.0	3,472.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,472.6
PSEG	PSEG	0.0	5,429.8	0.0	0.0	18.2	175.0	3.0	0.0	374.8	221.9	0.0	6,222.7
Rest of PSEG	PSEG	0.0	2,125.2	0.0	0.0	18.2	77.3	0.0	0.0	201.5	154.0	0.0	2,576.2
PSEG North	PSEG	0.0	3,304.6	0.0	0.0	0.0	97.7	3.0	0.0	173.3	67.9	0.0	3,646.5
Rest of EMAAC	RECO	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.6	7.0	0.0	12.6
Total New Jersey		458.9	9,820.9	3,472.6	239.0	88.6	185.0	324.1	0.0	613.8	426.1	0.0	15,629.0

demand. To avoid double counting, the amount of energy efficiency capacity included in the FRR plan is added back to the FRR obligation.

12 The ICAP MW values reflect administrative reductions applied by PJM to the capabilities of wind generators to 14.7 percent for wind farms in mountainous terrain and 17.6 percent for wind farms in open terrain, and solar generators to 42.0 percent for ground mounted fixed panel, 60.0 percent for ground mounted tracking panel, and 38.0 percent for other than ground mounted solar arrays, of nameplate capacity when determining the installed capacity.

13 ICAP values, rather than UCAP, are used for confidentiality reasons and the ICAP values represent resources that were offered into the 2021/2022 RPM Base Residual Auction. Resources that were not offered into 2021/2022 RPM Base Residual Auction are not included in this table. Seasonal resources that were offered into the 2021/2022 RPM Base Residual Auction but were not matched and included as FRR capacity for this study are not included in this table.

14 One solid waste power plant that is physically located outside New Jersey but electrically located in New Jersey is included in Table 3.

New Jersey's renewable portfolio standard (RPS) has a target of 50 percent renewable energy by 2030.[15] The 2030 target includes an additional requirement that 1.58 percent of energy consumption be sourced from solar generators.[16] New Jersey's target for offshore wind capacity was increased from 3,500 MW by 2030 to 7,500 MW by 2035.[17] The NJ Board of Public Utilities (BPU) opened a 100 day application window for qualified offshore wind projects on September 20, 2018, and on June, 21, 2019, the first award for a 1,100 MW offshore wind project was granted to Ørsted.[18] [19] [20] The RPS for 2020 requires 21.0 percent renewable with 4.9 percent sourced from solar. The New Jersey FRR capacity for this study includes 311.5 MW of tier 1 renewable resources, with 88.6 MW being zero carbon.[21]

The most recent data from New Jersey shows that renewable energy production from New Jersey resources was 735.5 GWh in 2019, or 1.2 percent of New Jersey energy production in 2019. In 2018, renewable energy production from New Jersey resources was 655.0 GWh, or 1.0 percent of New Jersey energy production. New Jersey also imports significant levels of renewable energy in order to meet RPS targets. In the 2018/2019 compliance year, New Jersey imported 97.7 percent of the total RECs that met class I RPS standards; 88.7 percent of the imported class I RECs were from renewable

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15 New Jersey's RPS definition is not zero carbon. New Jersey's RPS definition of class I renewable resources includes wind, solar, waste to energy, geothermal, and landfill gas technologies. Waste to energy, geothermal, and landfill gas energy production result in carbon emissions.

16 New Jersey also has an offshore wind capacity target of 7,500 MW by 2031. This requirement has not been incorporated into the current RPS rules. See Executive Order 92, Philip D. Murphy, Governor of New Jersey (November 19, 2019) <https://nj.gov/infobank/eo/056murphy/approved/eo_archive.html>.

17 Executive Order 92, Philip D. Murphy, Governor of New Jersey (November 19, 2019) <https://nj.gov/infobank/eo/056murphy/approved/eo_archive.html>.

18 BPU Docket No. QO18080851.

19 "New Jersey Board of Public Utilities Awards Historic 1,100 MW Offshore Wind Solicitation to Ørsted's Ocean Wind Project," New Jersey BPU Press Release (June 21, 2019) <https://nj.gov/bpu/newsroom/2019/approved/20190621.html>.

20 The Ocean Wind Project will be completed in three phases. Phase 1 commercial operation date is May 1, 2024. Phase 2 commercial operating date is September 1, 2024 and phase 3 commercial operating date is December 1, 2024. See June 21, 2019 Order, BPU Docket No. Q018121289 <https://www.state.nj.us/bpu/agenda/orders/>.

21 The tier I total includes 37.9 MW of landfill gas capacity and 185.0 waste to energy capacity in addition to the solar generation.

energy resources. Out of state resources are not eligible to participate in New Jersey's solar program; 2,747,676 SRECs were retired in 2018/2019 compliance year.[22]

Market share is calculated by dividing the output of a supplier by total supply in a market. Concentration ratios are a summary measure of market share. The Herfindahl-Hirschman Index (HHI) concentration ratio is calculated by summing the squares of the market shares of all firms in a market.

FERC's Merger Policy Statement states that a market can be broadly characterized as: unconcentrated if the market HHI is below 1000, equivalent to 10 firms with equal market shares; moderately concentrated if the market HHI is between 1000 and 1800; and highly concentrated if the market HHI is greater than 1800, equivalent to between five and six firms with equal market shares.[23]

Table 4 shows the HHI results for the FRRs analyzed. The HHI results show that the PSEG and NJ FRRs are highly concentrated and that the JCPL FRR is moderately concentrated.

Table 4 HHI results

Market	HHI
JCPL	1572
PSEG	5562
New Jersey	2445

The HHI is not a definitive measure of structural market power. The number of pivotal suppliers in the capacity market is a more precise measure of structural market power than the HHI. It is possible to have pivotal suppliers in a market even when the HHI level is not in the highly concentrated range. The three pivotal supplier test can show the existence of structural market power when the HHI is less than 2500 and the maximum market share is less than 20 percent. The three pivotal supplier test can also show the absence of market power when the HHI is greater than 2500 and the maximum market share is greater than 20 percent. The three pivotal supplier test is more accurate than the HHI and market share tests because it focuses on the relationship between demand and the ownership structure of supply available to meet it.

A generation owner or owners are pivotal if the capacity of the owners' generation facilities is needed to meet the demand for capacity. The results of the pivotal supplier test are measured by the residual supply index (RSI_X). The RSI_X is a general measure that can be used with any number of pivotal suppliers. The subscript denotes the number of

22 PJM EIS GATS.

23 See *Inquiry Concerning the Commission's Merger Policy under the Federal Power Act: Policy Statement, 77* FERC ¶ 61,263 *mimeo* at 80 (1996).

pivotal suppliers included in the test. If the RSI_X is less than or equal to 1.0, the supply owned by the specific generation owner, or owners, is needed to meet market demand and the generation owners are pivotal suppliers with a significant ability to influence market prices.

Table 5 shows the results of the pivotal supplier test for the FRRs analyzed. All participants in the New Jersey, JCPL, and PSEG FRRs fail the one and three pivotal supplier test (RSI is less than 1.0).[24]

Table 5 Pivotal supplier results

Market	$RSI_{1, 1.05}$	RSI_3	Total Participants	Failed RSI_3 Participants
JCPL	0.79	0.41	16	16
PSEG	0.27	0.08	17	17
New Jersey	0.53	0.38	33	33

Table 6 shows zonal UCAP obligation for each zone in New Jersey. All four zones in New Jersey (AECO, JCPL, PSEG and RECO) are entirely located in New Jersey. This is the capacity obligation assigned to New Jersey and each New Jersey zone in the PJM Capacity Market. For example, the zonal UCAP obligation for the entire AECO Zone is 2,687.1 MW. The entire AECO Zone is within New Jersey. New Jersey's share of the AECO Zone zonal UCAP obligation is 2,687.1 MW. The PSEG Zone includes PSEG North and Rest of PSEG LDAs. The zonal UCAP obligation for the entire PSEG Zone is 10,901.1 MW, of which the share of PSEG North is 5,336.1 MW. The total New Jersey zonal UCAP obligation for 2021/2022 Delivery Year is 20,568.1 MW.[25]

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24 The one pivotal supplier test and the three pivotal supplier test here include all market supply and all market demand for each FRR.

25 The reliability requirement for an LDA is the projected internal capacity in the LDA plus the capacity emergency transfer objective (CETO) for the delivery year. The CETO is calculated to meet 1 day in 25 year loss of load expectation for an LDA. See "PJM Manual 18: PJM Capacity Market," § 2.4.2 Reliability Requirement in Locational Deliverability Areas, Rev. 43 (Dec. 3, 2019). The FPR is calculated to meet 1 day in 10 year loss of load expectation for an LDA. See "PJM Manual 20: PJM Capacity Market," § 1.7 Compliance with ReliabilityFirst (RF), Rev. 10 (March 21, 2019).

Table 6 New Jersey share of the zonal UCAP obligation by transmission zone[26]

Zone	Share of the Peak Load (Percent)	Zonal UCAP Obligation (MW)	New Jersey Share of Zonal UCAP Obligation (MW)
AECO	100.0%	2,687.1	2,687.1
JCPL	100.0%	6,538.6	6,538.6
PSEG	100.0%	10,901.1	10,901.1
Rest of PSEG	100.0%	5,565.0	5,565.0
PSEG North	100.0%	5,336.1	5,336.1
RECO	100.0%	441.3	441.3
New Jersey		20,568.1	20,568.1

Table 7 shows the FRR UCAP MW obligation for each zone in New Jersey. All four zones in New Jersey (AECO, JCPL, PSEG and RECO) are entirely located in New Jersey. This is the capacity obligation that would be assigned to New Jersey and each New Jersey zone if each were an FRR. The FRR obligation includes the EE add back. The FRR obligation is based on the PJM peak load forecast for the delivery year. The PJM peak load forecast is assumed to account for the contribution of energy efficiency resources because load is assumed to be reduced by the energy efficiency resources.[27] Consistent with the approach PJM uses in the capacity auctions, the amount of energy efficiency capacity included in the FRR plan is added back to the FRR obligation to avoid the double counting that would result from including EE as a supply side resource and as a reduction to the peak load forecast,. For example, the FRR UCAP obligation for AECO is defined as the AECO zonal forecast peak load (2,308.0 MW) times the forecast pool requirement (1.0898), or 2,515.3 MW plus the EE add back (38.7 MW) or 2,554.0 MW. The PSEG Zone includes PSEG North and Rest of PSEG LDAs. The FRR obligation for the entire PSEG Zone is 10,445.6 MW, of which the share of PSEG North is 5,068.8 MW. The total New Jersey FRR obligation including the EE add back for the 2021/2022 Delivery Year is 19,715.8 MW.

[26] The column totals exclude the zonal UCAP obligations for sub zones: Rest of PSEG and PSEG North, to avoid double counting.

[27] There are significant issues with the measurement and verification of EE. See the *2019 State of the Market Report for PJM*, Volume 2, Section 6: Demand Response pg. 314.

Table 7 New Jersey share of the peak load, peak load forecast and FRR obligation by transmission zone[28 29]

Zone	Share of the Peak Load (Percent)	Zonal Peak Load Forecast (MW)	FRR UCAP Obligation (MW) plus EE add back
AECO	100.0%	2,308.0	2,554.0
JCPL	100.0%	5,616.0	6,295.9
PSEG	100.0%	9,363.0	10,445.6
Rest of PSEG	100.0%	4,779.8	5,376.8
PSEG North	100.0%	4,583.2	5,068.8
RECO	100.0%	379.0	420.3
Total		17,666.0	19,715.8

Comparing Table 6 with Table 7 shows the zonal FRR UCAP obligations are lower than the UCAP obligations in the capacity market. The reduced obligations are a result of the fact that the RPM auction clearing uses sloped demand curves (Variable Resource Requirement or VRR curves) while the FRR Entities use vertical demand curves based on a fixed MW requirement. Under the current rules for every LDA, the calculated reliability requirement reflects the more stringent 1 day in 25 years loss of load expectation. The calculated RTO wide reliability requirement reflects the less stringent 1 day in 10 years loss of load expectation. The difference in reliability standards for an individual LDA and the RTO is intended to capture the diversity benefit. However, if a New Jersey FRR service area were created, the FRR UCAP obligation reflects only the 1 day in 10 years loss of load expectation, which is a less stringent reliability standard than the 1 day in 25 years that would apply if New Jersey remained in the PJM Capacity Market.[30]

Table 8 shows that the total capacity in New Jersey offered in the 2021/2022 RPM BRA is not enough to meet the New Jersey FRR obligation. LSEs in New Jersey would need to secure capacity both from resource owners in New Jersey and capacity resources outside New Jersey to meet the FRR UCAP obligation for the New Jersey FRR service area.

Table 8 shows unforced capacity offered, FRR UCAP obligation plus the EE add back and shortfall in each New Jersey LDA. In the 2021/2022 BRA, 5,951.6 MW UCAP were

28 The contribution percentages are the five year historical average of the New Jersey portion of each zone's load during the yearly maximum load hour.

29 The column totals exclude the FRR UCAP obligations for sub zones: Rest of PSEG and PSEG North, to avoid double counting.

30 This result, which has been part of the RPM design from its inception, should be reviewed to ensure its consistency with the design of FRRs and the capacity market. In the future, this rule could be changed to ensure consistency.

offered in the PSEG LDA. The PSEG FRR obligation for the 2021/2022 Delivery Year is 10,445.6 MW. The PSEG LDA needs to import 4,494.0 MW UCAP or 43.0 percent of the FRR UCAP obligation from capacity resources located outside the PSEG LDA. The entire PSEG LDA, which includes PSEG North LDA, is located within the PSEG Zone. The PSEG Zone also includes a portion of the Rest of EMAAC LDA. The PSEG obligation can be met in significant part by imports from the portion of the Rest of EMAAC inside the PSEG Zone.

Table 8 Capacity, FRR obligation and shortfall for New Jersey by LDA[31] [32]

Modeled LDA	Zone	Capacity (UCAP MW)	FRR Obligation (UCAP MW) plus EE add back	Shortfall (UCAP MW)	Shortfall (Percent)
Rest of EMAAC	AECO	1,879.2	2,554.0	(674.8)	(26.4%)
Rest of EMAAC	JCPL	3,847.9	6,295.9	(2,448.0)	(38.9%)
Rest of EMAAC	PSEG	3,313.2	NA	NA	NA
PSEG	PSEG	5,951.6	10,445.6	(4,494.0)	(43.0%)
Rest of PSEG	PSEG	2,462.2	5,376.8	(2,914.6)	NA
PSEG North	PSEG	3,489.4	5,068.8	(1,579.4)	NA
Rest of EMAAC	RECO	13.3	420.3	(407.0)	(96.8%)
Total New Jersey		15,005.2	19,715.8	(4,710.6)	(23.9%)

Table 9 shows the LDA, modeled LDA and parent LDA for each zone in New Jersey. All transmission zones are LDAs, but there are also additional LDAs, including parts of zones in some cases and multiple zones in other cases. Not all LDAs are modeled separately in the PJM capacity market auctions. Of the four LDAs in New Jersey, all LDAs are entirely within New Jersey. The PSEG Zone in New Jersey includes the PSEG LDA, which includes the entire PSEG North LDA, and the PSEG portion of the Rest of EMAAC LDA, both of which are part of the EMAAC parent LDA. The AECO Zone, JCPL Zone and RECO Zone are not modeled LDAs and are part of the EMAAC parent LDA.

31 The capacity includes the annual equivalent of matched seasonal resources. Since the 2020/2021 Delivery Year, RPM rules allow seasonal resources to offer in the capacity market. Complementary seasonal capacity resources are matched within the auction clearing process.

32 The column totals exclude the FRR Obligation and shortfall for subzones: Rest of PSEG and PSEG North, to avoid double counting.

Table 9 LDA and parent LDA of zones located in New Jersey

Zone	LDA	Modeled LDAs	Parent LDA
AECO	AECO	Rest of EMAAC	MAAC
JCPL	JCPL	Rest of EMAAC	MAAC
PSEG	PSEG	PSEG, PSEG North	EMAAC
RECO	RECO	Rest of EMAAC	MAAC

The PSEG Zone, excluding the PSEG portion of the Rest of EMAAC, is a modeled LDA. The portion of PSEG LDA called PSEG North is also a modeled LDA. The Rest of EMAAC is a modeled LDA. The PSEG portion of the Rest of EMAAC LDA is not associated with any load or geographical region. It includes two generators both geographically located in New Jersey. These generators are connected to the high voltage transmission system.[33]

Table 10 shows the weighted average net CONE times B offer caps applicable to LDAs in New Jersey and the weighted average clearing prices in the 2021/2022 BRA.[34] [35]

33 PJM defines EMAAC as a Global LDA and PSEG as a Zonal LDA. The PJM definition of the parent EMAAC LDA includes all generation and load connected to the 500 kV and lower transmission system in the PSEG Zone. The PJM definition of the PSEG LDA includes only generation and load connected to the 345 kV and lower transmission system. See "PJM Manual 14 B: PJM Region Transmission Planning Process," § C2.2 Current Locational Deliverability Area Definitions, Rev. 46 (August 28, 2019).

34 Weights are the zonal FRR UCAP obligations. These weights are used throughout the report when weighted average offer caps are calculated. There were no generation capacity resources offered in RECO in the 2021/2022 BRA. The offer cap applicable to RECO is not included in the calculation of weighted zonal FRR UCAP obligation.

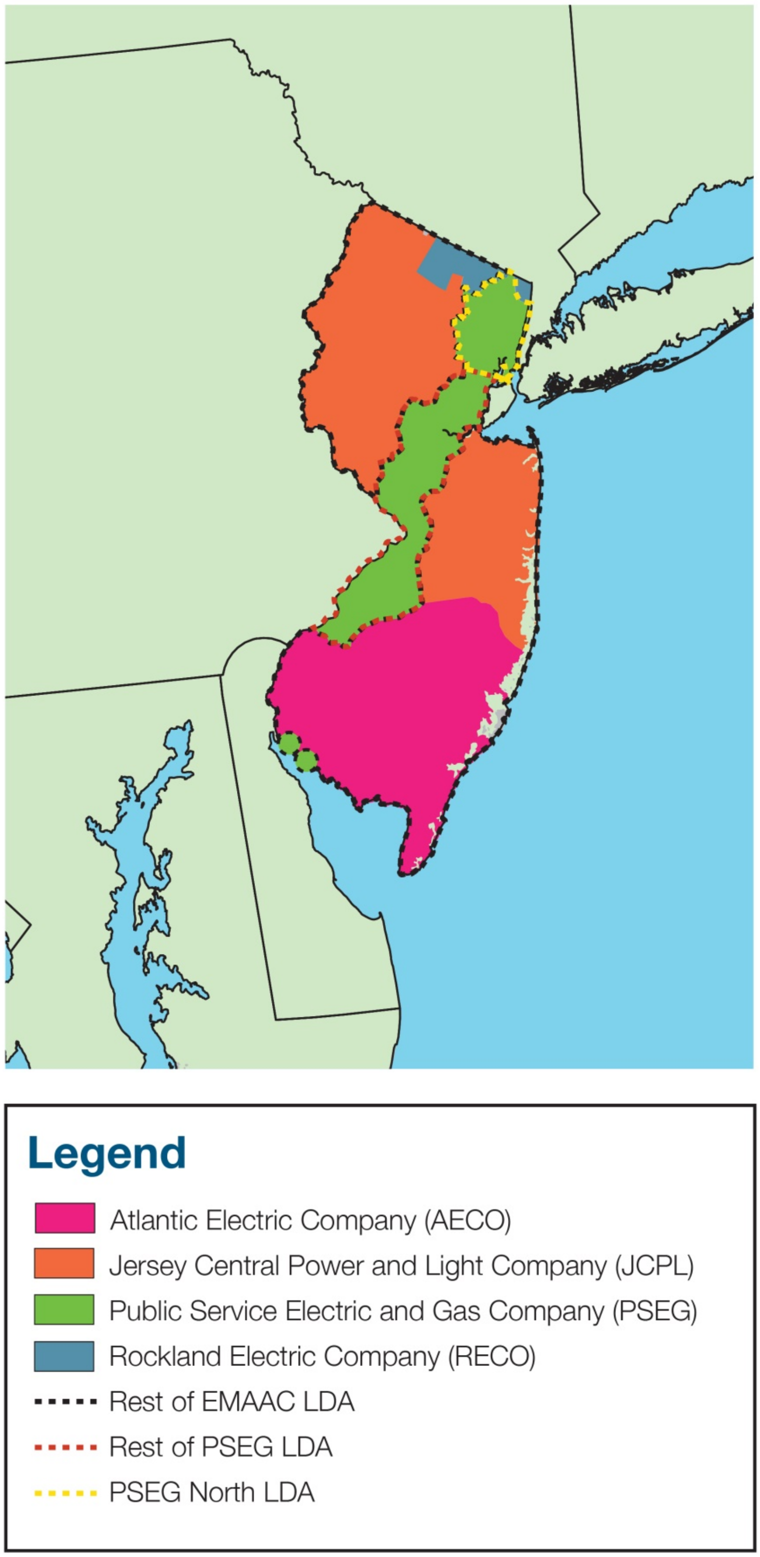
35 The net CONE times B offer caps are calculated by zone. The gross CONE values are very close across zones but net revenues vary. See Table 5 in "Analysis of the 2021/2022 RPM Base Residual Auction - Revised," <http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Analysis_of_the_20212022_RPM_BRA_Revised_20180824.pdf> (August 24, 2018).

Table 10 Net CONE times B offer cap for each zone in New Jersey and weighted average clearing price for New Jersey

Zone	FRR UCAP Obligation (MW) plus EE add back	Offer Cap ($ per MW-day)	2021/2022 BRA Clearing Price ($ per MW-day)
AECO	2,554.0	$243.80	$165.73
JCPL	6,295.9	$217.38	$165.73
PSEG	10,445.6	$244.24	$204.29
PSEG	5,376.8	$244.24	$204.29
PSEG North	5,068.8	$244.24	$204.29
RECO	420.3	NA	$165.73
New Jersey	19,715.8	$235.42	$186.16

Figure 1 is a map of the zones and modeled LDAs in New Jersey.

Figure 1 New Jersey zones and modeled locational deliverability areas



Existing FRR Design

The existing FRR approach remains an option for utilities with or without retail choice, including both investor owned and publicly owned utilities.[36] [37] Such utilities have had and continue to have the ability to opt out of the capacity market and provide their own capacity. There is no reason for any special exemptions for such utilities. Such utilities have the option to use the existing FRR option if they plan to continue to be cost of service based or wish to become cost of service based.

The RAA provides that states may require LSEs to become FRR entities.[38]

The Reliability Assurance Agreement (RAA) defines the purpose of the FRR alternative.[39]

> The Fixed Resource Requirement ("FRR") Alternative provides an alternative means, under the terms and conditions of this Schedule, for an eligible Load-Serving Entity to satisfy its obligation hereunder to commit Unforced Capacity to ensure reliable service to loads in the PJM Region.

The Reliability Assurance Agreement also defines the eligibility criteria for the FRR election.[40]

> A Party is eligible to select the FRR Alternative if it (a) is an IOU, Electric Cooperative, or Public Power Entity; and (b) demonstrates the capability to satisfy the Unforced Capacity obligation for all load in an FRR Service Area, including all expected load growth in such area, for the term of such Party's participation in the FRR Alternative.

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36 See "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 8.1.

37 The current FRR rules address areas with retail choice. See "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 8.1.D.8.

38 See "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 8.1.I.

39 See "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 8.1.A.

40 See "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 8.1.B.

> A Party eligible under B.1 above may select the FRR Alternative only as to all of its load in the PJM Region; provided however, that a Party may select the FRR Alternative for only part of its load in the PJM Region if (a) the Party elects the FRR Alternative for all load (including all expected load growth) in one or more FRR Service Areas; (b) the Party complies with the rules and procedures of the Office of the Interconnection and all relevant Electric Distributors related to the metering and reporting of load data and settlement of accounts for separate FRR Service Areas; and (c) the Party separately allocates its Capacity Resources to and among FRR Service Areas in accordance with rules specified in the PJM Manuals.

An IOU is defined in the PJM RAA as "an investor-owned utility with substantial business interest in owning and/or operating electric facilities in any two or more of the following three asset categories: generation, transmission, distribution."

An entity must request to elect the existing FRR option no later than four months prior to the BRA for the first delivery year of the election. An entity must under the existing FRR option submit its FRR capacity plan no later than one month prior to the BRA for the effective delivery year. The minimum term for election of the existing FRR option is five consecutive delivery years. Under the existing FRR option, an entity may terminate its FRR election following the minimum term by providing written notice to PJM no later than two months prior to the BRA for the effective delivery year. In the event of a State Regulatory Structural Change, an entity may elect or terminate its FRR election by providing written notice to PJM no later than two months prior to the BRA for the effective delivery year.[41]

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[41] State Regulatory Structural Change is defined as "to any Party, as a state law, rule, or order that, after September 30, 2006, initiates a program that allows retail electric consumers served by such Party to choose from among alternative suppliers on a competitive basis, terminates such a program, expands such a program to include classes of customers or localities served by such Party that were not previously permitted to participate in such a program, or that modifies retail electric market structure or market design rules in a manner that materially increases the likelihood that a substantial proportion of the customers of such Party that are eligible for retail choice under such a program (a) that have not exercised such choice will exercise such choice; or (b) that have exercised such choice will no longer exercise such choice, including for example, without limitation, mandating divestiture of utility-owned generation or structural changes to such Party's default service rules that materially affect whether retail choice is economically viable." See "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Article 1.

Public power entities and electric cooperatives could use the existing FRR option if they plan to continue to be cost of service based. To request the existing FRR option, public power entities or electric cooperatives need to demonstrate that the identified service area meets the definition of an FRR Service Area as defined in the RAA. The definition of FRR Service Area provides that "In the event that the service obligations of an Electric Cooperative or Public Power Entity are not defined by geographic boundaries but by physical connections to a defined set of customers, the FRR Service Area in such circumstances shall be defined as all customers physically connected to transmission or distribution facilities of such Electric Cooperative or Public Power Entity within an area bounded by appropriate wholesale aggregate metering as described above."

Under the current rules, an FRR entity can sell excess capacity in RPM auctions for a delivery year subject to a cap equal to the lesser of (a) 25 percent of the unforced capacity equivalent of the installed reserve margin for such delivery year multiplied by the preliminary forecast peak load for which such FRR entity is responsible under its FRR capacity plan(s) for such delivery year, or (b) 1,300 MW.[42] For New Jersey, JCPL, and PSEG, this cap would equal 1,300.0 MW. In order to sell excess capacity in RPM auctions for a delivery year, an FRR entity must commit additional capacity resources above its defined FRR UCAP obligation in an amount equal to the lesser of three percent of the FRR UCAP obligation or 450 MW.[43] For New Jersey, this additional threshold quantity would equal 445.0 MW. For JCPL, this additional threshold quantity would equal 183.6 MW. For PSEG, this additional threshold quantity would equal 156.3 MW.

Results

Scenario 1

In Scenario 1, an FRR is established that includes all of New Jersey and the FRR procures the entire New Jersey FRR UCAP obligation of 19,715.8 MW at a rate equal to the weighted average of the 2021/2022 net CONE times B offer caps applicable to the LDAs in New Jersey ($235.42 per MW-day).[44] New Jersey has 4,710.6 MW UCAP or 23.9

[42] See "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 8.1.E.2.

[43] See "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Article 1 and Schedule 8.1.E.

[44] The FRR UCAP obligation is defined as the [(obligation peak load * final zonal FRR scaling factor) – nominal PRD value committed by the FRR entity] * [forecast pool requirement + EE add back]. The final zonal FRR scaling factor equals the final zonal peak load forecast for the delivery year / zonal weather normalized peak load for the summer concluding prior to the start of the delivery year. See "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 8.1.F. The EE add back MW are determined by PJM in

percent fewer MW than needed to meet its FRR obligation. The New Jersey FRR would need to contract with capacity resources outside New Jersey to cover the deficit. If a New Jersey FRR service area were created, the New Jersey FRR would be required to procure 19,715.8 MW UCAP, 852.2 MW (4.1 percent) less than if New Jersey remained in the PJM Capacity Market. In Scenario 1, summer capacity resources in New Jersey are matched with winter capacity resources in New Jersey such that the total annual equivalent price is less than or equal to the weighted average of the 2021/2022 net CONE times B offer caps applicable to the LDAs in New Jersey ($235.42 per MW-day). The unmatched seasonal resources are mapped to the rest of EMAAC LDA.

This is a sensitivity analysis based on the assumption that the owners of capacity resources in the New Jersey FRR would request payment at the existing offer cap and that all capacity resources would be paid the same price. It is expected that the actual price for capacity in the New Jersey FRR would be the result of a negotiation between the owners of the required capacity, and the State of New Jersey.[45] The price for capacity resources could substantially exceed the capacity market clearing price and the capacity market offer cap.

Table 11 compares the clearing prices for the rest of the PJM Capacity Market by LDA for the 2021/2022 RPM BRA and for Scenario 1. All binding constraints would remain the same except that the EMAAC and ATSI constraints would not be binding and the DEOK constraint would be binding. The Rest of RTO LDA clearing price would decrease by $12.61 per MW-day from $140.00 per MW-day to $127.39 per MW-day, or 9.0 percent, from the Rest of the RTO clearing price in the 2021/2022 RPM BRA. The EMAAC LDA clearing price would decrease by $38.34 per MW-day from $165.73 per MW-day to $127.39 per MW-day, or 23.1 percent, from the EMAAC LDA clearing price in the 2021/2022 RPM BRA. The ATSI LDA clearing price would decrease by $43.94 per MW-day from $171.33 per MW-day to $127.39 per MW-day, or 25.6 percent, from the ATSI LDA clearing price in the 2021/2022 RPM BRA. The ComEd LDA clearing price would decrease by $6.54 per MW-day from $195.55 per MW-day to $189.01 per MW-day, or 3.3 percent, from the ComEd LDA clearing price in the 2021/2022 RPM BRA. The DEOK LDA clearing price would decrease by $11.53 per MW-day from $140.00 per MW-day to $128.47 per MW-day, or 8.2 percent, from the DEOK LDA clearing price in the 2021/2022 RPM BRA.

Table 12 shows the gross and net load charges to New Jersey for the 2021/2022 BRA and for Scenario 1. The net load charges when New Jersey is included in the PJM Capacity

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the BRA. See "PJM Manual 18B: Energy Efficiency Measurement & Verification," Rev. 04 (Aug. 22, 2019).

45 This could also include the owners of capacity that could be imported, limited by the CETL.

Market are net of Capacity Transfer Rights (CTRs) payments to load.[46] CTRs are analogous to FTRs in the energy market and return capacity market congestion revenues to load. Capacity market congestion revenues are the difference between the total dollars paid by load for capacity and the total dollars received by capacity market sellers. The difference exists because load pays for all capacity at the single LDA clearing price despite the fact that the capacity imported into the LDA receives a lower price. Credits for CTRs do not exist with an FRR because the CTR credits are based on the operation of the integrated PJM Capacity Market with locational pricing. The FRR entity would no longer be in the PJM Capacity Market and the rules governing price formation in the capacity market would no longer apply.[47]

Table 12 shows that, based on actual auction clearing prices and quantities, make whole MW and RPM zonal UCAP obligation, gross load charges for the 2021/2022 RPM BRA for New Jersey were $1,402,173,465. In the 2021/2022 RPM BRA, only 5,367.6 MW UCAP of PSEG capacity resources cleared. The PSEG LDA needed an additional 5,533.5 MW UCAP to meet the PSEG zonal UCAP obligation. The CTR credits received by the PSEG LDA are based on the UCAP MW needed to meet the PSEG UCAP obligation. The PSEG LDA imported 6,902.0 MW of capacity from the rest of the EMAAC LDA. The clearing price for the PSEG LDA was $38.56 per MW-day higher than the clearing price for the rest of the EMAAC LDA. The load in the PSEG Zone received CTR credits of $83,093,233. The load in the other zones in New Jersey received CTR credits of $11,399,731. After accounting for CTRs, the net load charges for the 2021/2022 RPM BRA for New Jersey were $1,307,680,502.

If a New Jersey FRR were created and the capacity price for New Jersey were equal to the weighted average net CONE times B offer caps applicable to the LDAs in New Jersey ($235.42 per MW-day), the load charges for New Jersey would have been $1,694,128,606, an increase of $386,448,104, or 29.6 percent higher than in the 2021/2022 BRA. (Table 12)

[46] The MW of CTRs available for allocation to LSEs in an LDA is equal to the unforced capacity imported into the LDA determined based on the results of the Base Residual Auction and Incremental Auctions, less any MW of CETL paid for directly by market participants which include Qualifying Transmission Upgrades (QTUs) cleared in an RPM Auction and Incremental Capacity Transfer Rights (ICTRs). The price of the CTR credits is the locational adder for the LDA.

[47] If an FRR entity could pay imported capacity a lower price than it pays internal capacity, the difference would be analogous to a CTR credit. But increased reliance on internal resources in an FRR reduces the quantity of imports and the potential size of any such credit. In addition, the prices in the rest of the RTO are a function of the level of imports by the FRR entity, so if more imports are assumed the price in the rest of RTO would also be higher.

The higher load charges in Scenario 1 compared to the results of the 2021/2022 BRA are the result of higher prices and the elimination of CTRs, which more than offset the lower FRR UCAP obligation for the load in New Jersey.

Table 13 shows the net load charges for the RTO excluding the load in the New Jersey FRR for Scenario 1. Based on actual auction clearing prices and quantities, make whole MW and the RPM zonal UCAP obligation, the gross load charges for the 2021/2022 RPM BRA, for the RTO excluding the New Jersey FRR, were $8,312,797,707. After accounting for CTRs, the net load charges for the 2021/2022 RPM BRA for the RTO excluding New Jersey were $8,079,164,173.

Under Scenario 1, the gross load charges for the 2021/2022 RPM BRA for the RTO excluding New Jersey would have been $7,467,303,983. After accounting for CTRs, the net load charges for the 2021/2022 RPM BRA, for the RTO excluding New Jersey, would have been $7,295,237,509, a reduction of $783,926,664 or 9.7 percent.

If New Jersey were to subsidize any generating units, the subsidy costs would be in addition to the direct FRR costs.

Table 11 Clearing prices in Scenario 1 and Scenario 2 compared to the actual BRA results

LDA	2021/2022 BRA	Scenario 1 and Scenario 2	Change	Percent
Rest of RTO	$140.00	$127.39	($12.61)	(9.0%)
Rest of MAAC	$140.00	$127.39	($12.61)	(9.0%)
Rest of EMAAC	$165.73	$127.39	($38.34)	(23.1%)
Rest of SWMAAC	$140.00	$127.39	($12.61)	(9.0%)
Rest of PSEG	$204.29	NA	NA	NA
PSEG North	$204.29	NA	NA	NA
DPL South	$165.73	$127.39	($38.34)	(23.1%)
Pepco	$140.00	$127.39	($12.61)	(9.0%)
Rest of ATSI	$171.33	$127.39	($43.94)	(25.6%)
ATSI Cleveland	$171.33	$127.39	($43.94)	(25.6%)
ComEd	$195.55	$189.01	($6.54)	(3.3%)
BGE	$200.30	$200.30	$0.00	0.0%
PPL	$140.00	$127.39	($12.61)	(9.0%)
DAY	$140.00	$127.39	($12.61)	(9.0%)
DEOK	$140.00	$128.47	($11.53)	(8.2%)

Table 12 Net load charges for New Jersey (Scenario 1)[48]

New Jersey FRR	BRA	Scenario 1	Change	Percent
Zonal UCAP Obligation (MW UCAP)	20,568.1	19,715.8	(852.2)	(4.1%)
Zonal Capacity Price ($/MW-day)	$186.77	$235.42	$48.64	26.0%
Gross Load Charges	$1,402,173,465	$1,694,128,606	$291,955,141	20.8%
Value of CTRs	$94,492,963	$0	($94,492,963)	(100.0%)
Net Load Charges	$1,307,680,502	$1,694,128,606	$386,448,104	29.6%

Table 13 Net load charges for RTO excluding New Jersey (Scenario 1)

RTO (Excluding New Jersey)	BRA	Scenario 1 and Scenario 2	Change	Percent
Zonal UCAP Obligation	143,059.2	143,267.8	208.6	0.1%
Gross Load Charges	$8,312,797,707	$7,467,303,983	($845,493,724)	(10.2%)
Value of CTRs	$233,633,534	$172,066,474	($61,567,060)	(26.4%)
Net Load Charges	$8,079,164,173	$7,295,237,509	($783,926,664)	(9.7%)

Scenario 2

In Scenario 2, an FRR is established that includes all of New Jersey and the FRR procures the entire New Jersey FRR UCAP obligation of 19,715.8 MW at a rate equal to the weighted average clearing prices in the 2021/2022 RPM BRA applicable to the LDAs in New Jersey ($186.16 per MW-day). New Jersey has 4,710.6 MW UCAP or 23.9 percent fewer MW than needed to meet its FRR obligation. The New Jersey FRR would need to contract with capacity resources outside New Jersey to cover the deficit. If a New Jersey FRR service area were created, New Jersey would be required to procure 19,715.8 MW UCAP, 852.2 MW (4.1 percent) less than if New Jersey remained in the PJM Capacity Market. In Scenario 2, summer capacity resources in New Jersey are matched with winter capacity resources in New Jersey such that the total annual equivalent price is less than or equal to the weighted average clearing prices in the 2021/2022 RPM BRA applicable to the LDAs in New Jersey ($186.16 per MW-day). The unmatched seasonal resources are mapped to the rest of EMAAC LDA.

Table 11 compares the clearing prices for the rest of the PJM Capacity Market by LDA for the 2021/2022 RPM BRA and for Scenario 1. All binding constraints would remain the same except the EMAAC and ATSI constraints would not be binding and the DEOK constraint would also be binding. The Rest of RTO LDA clearing price would decrease by $12.61 per MW-day from $140.00 per MW-day to $127.39 per MW-day, or 9.0 percent, from the Rest of the RTO clearing price in the 2021/2022 RPM BRA. The EMAAC LDA clearing price would decrease by $38.34 per MW-day from $165.73 per MW-day to $127.39 per MW-day, or 23.1 percent, from the EMAAC LDA clearing price in the

48 The net load charges for the BRA include make whole payments. The gross load charges for the delivery year are calculated using the unrounded zonal capacity price.

2021/2022 RPM BRA. The ATSI LDA clearing price would decrease by $43.94 per MW-day from $171.33 per MW-day to $127.39 per MW-day, or 25.6 percent, from the ATSI LDA clearing price in the 2021/2022 RPM BRA. The ComEd LDA clearing price would decrease by $6.54 per MW-day from $195.55 per MW-day to $189.01 per MW-day, or 3.3 percent, from the ComEd LDA clearing price in the 2021/2022 RPM BRA. The DEOK LDA clearing price would decrease by $11.53 per MW-day from $140.00 per MW-day to $128.57 per MW-day, or 8.2 percent, from the DEOK LDA clearing price in the 2021/2022 RPM BRA.

Table 14 shows the gross and net load charges to New Jersey for the 2021/2022 BRA and for Scenario 2. The net load charges when New Jersey is included in the PJM Capacity Market are net of CTRs.

Table 14 shows that, based on actual auction clearing prices and quantities, make whole MW and the RPM zonal UCAP obligation, gross load charges for the 2021/2022 RPM BRA for New Jersey were $1,402,173,465. In the 2021/2022 RPM BRA, only 5,367.6 MW UCAP of PSEG capacity resources cleared. The PSEG LDA needed an additional 5,533.5 MW UCAP to meet the PSEG zonal UCAP obligation. The CTR credits received by the PSEG LDA are based on the UCAP MW needed to meet the PSEG UCAP obligation. The PSEG LDA imported 6,902.0 MW of capacity from the rest of the EMAAC LDA, consistent with the CETL value for PSEG LDA. The clearing price for the PSEG LDA was $38.56 per MW-day higher than the clearing price of the Rest of the EMAAC LDA. The load in the PSEG Zone received CTR credits of $83,093,233. The load in the others zones in New Jersey received CTR credits of $11,399,731. After accounting for CTRs, the net load charges for the 2021/2022 RPM BRA for New Jersey were $1,307,680,502.

If a New Jersey FRR were created and the capacity price for New Jersey were equal to the weighted average of the New Jersey LDAs' clearing prices in the BRA ($186.16 per MW-day), the load charges for New Jersey would have been $1,339,653,257, an increase of $31,972,755, or 2.4 percent higher than in the 2021/2022 BRA.[49]

The higher load charges in Scenario 2 compared to the results of the 2021/2022 BRA are the result of the same clearing prices and the elimination of CTRs, which more than offsets the lower FRR UCAP obligation for the load in New Jersey.

49 The $186.77 per MW-day is the Zonal UCAP Obligation weighted average net load price for New Jersey, the capacity price charged to the load in the Zones within New Jersey. In the 2021/2022 BRA, the FRR Obligation adjusted for EE add back, weighted resource clearing price for New Jersey was $186.16 per MW-day. The difference of $0.61 per MW-day was due to New Jersey's portion of funding for cleared Price Responsive Demand (PRD) credits and make whole payments to the seasonal resources.

Table 15 shows the net load charges for the RTO excluding the load in New Jersey for Scenario 2. The net load charges for the RTO excluding New Jersey are the same as Scenario 1.

If New Jersey were to subsidize any generating units, the subsidy costs would be in addition to the direct FRR costs.

Table 14 Net load charges for New Jersey (Scenario 2)

New Jersey FRR	BRA	Scenario 2	Change	Percent
Zonal UCAP Obligation	20,568.1	19,715.8	(852.2)	(4.1%)
Zonal Capacity Price ($/MW-day)	$186.77	$186.16	($0.61)	(0.3%)
Gross Load Charges	$1,402,173,465	$1,339,653,257	($62,520,208)	(4.5%)
Value of CTRs	$94,492,963	$0	($94,492,963)	(100.0%)
Net Load Charges	$1,307,680,502	$1,339,653,257	$31,972,755	2.4%

Table 15 Net load charges for RTO excluding New Jersey (Scenario 2)

RTO (Excluding New Jersey)	BRA	Scenario 1 and Scenario 2	Change	Percent
Zonal UCAP Obligation	143,059.2	143,267.8	208.6	0.1%
Gross Load Charges	$8,312,797,707	$7,467,303,983	($845,493,724)	(10.2%)
Value of CTRs	$233,633,534	$172,066,474	($61,567,060)	(26.4%)
Net Load Charges	$8,079,164,173	$7,295,237,509	($783,926,664)	(9.7%)

Scenario 3

In Scenario 3, an FRR is established for the PSEG LDA and the FRR procures the entire PSEG capacity obligation at a rate equal to the 2021/2022 net CONE times B offer cap for PSEG ($244.24 per MW-day). The PSEG FRR has 4,494.0 MW UCAP or 43.0 percent fewer MW than needed to meet its FRR obligation. The PSEG FRR would need to contract with the owners of capacity resources outside the PSEG FRR to cover the deficit. If a PSEG FRR service area were created, the PSEG FRR would be required to procure 10,445.6 MW UCAP, 455.5 MW (4.2 percent) less than if the PSEG LDA remained in the PJM Capacity Market. In Scenario 3, summer capacity resources in the PSEG LDA are matched with winter capacity resources in the PSEG LDA such that the total annual equivalent price is less than or equal to the 2021/2022 net CONE times B offer cap for PSEG ($244.24 per MW-day). The unmatched seasonal resources are mapped to the rest of EMAAC LDA.

This is a sensitivity analysis based on the assumption that the owners of capacity resources needed to meet the reliability requirements in the PSEG FRR would request payment at the existing offer cap and that all capacity resources would be paid the same price. It is assumed that the actual price for capacity in the PSEG FRR would be the result of a negotiation between the owners of the required capacity, and the State of New Jersey. The price for capacity resources could substantially exceed the capacity market clearing price and the capacity market offer cap.

Table 16 compares the clearing prices for the rest of the PJM Capacity Market by LDA for the 2021/2022 RPM BRA and for Scenario 3. All binding constraints would remain the same and the DEOK LDA constraint would also be binding. The Rest of RTO LDA clearing price would decrease by $31.27 per MW-day from $140.00 per MW-day to $108.73 per MW-day, or 22.3 percent, from the rest of the RTO LDA clearing price in the 2021/2022 RPM BRA. The EMAAC LDA clearing price would decrease by $10.73 per MW-day from $165.73 per MW-day to $155.00 per MW-day, or 6.5 percent, from the EMAAC clearing price in the 2021/2022 RPM BRA. The DEOK LDA clearing price would decrease by $11.53 per MW-day from $140.00 per MW-day to $128.47 per MW-day, or 8.2 percent, from the DEOK LDA clearing price in the 2021/2022 RPM BRA.

The AECO Zone clearing price would decrease by $10.73 per MW-day from $165.73 per MW-day to $155.00 per MW-day or 6.5 percent from the AECO Zone clearing price in the 2021/2022 RPM BRA. The JCPL Zone clearing price would decrease by $10.73 per MW-day from $165.73 per MW-day to $155.00 per MW-day or 6.5 percent from the JCPL Zone clearing price in the 2021/2022 RPM BRA. The RECO Zone clearing price would decrease by $10.73 per MW-day from $165.73 per MW-day to $155.00 per MW-day or 6.5 percent from the RECO Zone clearing price in the 2021/2022 RPM BRA.

Table 17 shows the gross and net load charges to the PSEG FRR for the 2021/2022 BRA and for Scenario 3. The net load charges when the PSEG LDA is included in the PJM Capacity Market are net of CTR payments to load.

Table 17 shows that, based on actual auction clearing prices and quantities, make whole MW and RPM zonal UCAP obligation, gross load charges for the 2021/2022 RPM BRA for PSEG LDA were $815,342,184. In the 2021/2022 RPM BRA, only 5,367.6 MW UCAP of PSEG capacity resources cleared. The PSEG LDA needed 5,533.5 MW UCAP to meet the PSEG zonal UCAP obligation. The CTR credits received by the PSEG LDA are based on the UCAP MW needed to meet the PSEG UCAP obligation. The PSEG LDA imported 6,902.0 MW of capacity from the rest of EMAAC LDA. The clearing price for the PSEG LDA was $38.56 per MW-day higher than the clearing price of the rest of the EMAAC LDA. The load in the PSEG Zone received CTR credits of $83,093,233. After accounting for CTRs, the net load charges for the 2021/2022 RPM BRA for the PSEG LDA were $732,248,951.

If a PSEG FRR were created and the capacity price for the PSEG Zone were the net CONE times B offer cap ($244.24 per MW-day), the load charges for the PSEG Zone would have been $931,199,939, an increase of $198,950,988, or 27.2 percent higher than in the 2021/2022 BRA.

The higher load charges in Scenario 3 compared to the results of the 2021/2022 BRA are the result of higher prices and the elimination of CTRs, which more than offset the lower FRR UCAP obligation for the load in PSEG.

Table 18 shows the net load charges for the RTO excluding the load in the PSEG FRR for Scenario 3. Based on actual auction clearing prices and quantities, make whole MW and RPM zonal UCAP obligation, the gross load charges for the 2021/2022 RPM BRA, for the RTO excluding the PSEG FRR were $8,899,628,988. After accounting for CTRs, the net load charges for the 2021/2022 RPM BRA for the RTO excluding the PSEG FRR were $8,654,595,724.

Under Scenario 3, the gross load charges for the 2021/2022 RPM BRA, for the RTO excluding the PSEG FRR would have been $7,946,819,327. After accounting for CTRs, the net load charges for the 2021/2022 RPM BRA, for the RTO excluding the PSEG FRR would be $7,510,313,368, a reduction of $1,144,282,356 or 13.2 percent.

Table 19 shows the net load charges for New Jersey excluding the load in the PSEG FRR for Scenario 3. Based on actual auction clearing prices and quantities, make whole MW and RPM zonal UCAP obligation, the gross load charges for the 2021/2022 RPM BRA, for New Jersey excluding the PSEG FRR were $586,831,281. After accounting for CTRs, the net load charges for the 2021/2022 RPM BRA for New Jersey excluding the PSEG FRR were $575,431,550.

Under Scenario 3, the gross load charges for the 2021/2022 RPM BRA, for New Jersey excluding the PSEG FRR would have been $551,848,868. After accounting for CTRs, the net load charges for the 2021/2022 RPM BRA, for New Jersey excluding the PSEG FRR would be $533,174,167, a reduction of $42,257,383 or 7.3 percent.

Table 20 shows the change in the net load charges for PSEG, the rest of New Jersey and New Jersey. Under Scenario 3, the net load charges for PSEG would increase by 27.2 percent. The net load charges for New Jersey excluding the PSEG FRR would decrease by 7.3 percent. The net load charges for New Jersey would increase by 12.0 percent. The reduction in load charges for the rest of New Jersey due to the decrease in clearing prices in AECO, JCPL and RECO Zones partially offsets the increase in the net load charges for the PSEG LDA.

If New Jersey were to subsidize any generating units, the subsidy costs would be in addition to the direct FRR costs.

Table 16 Clearing prices in Scenario 3 and Scenario 4 compared to the actual BRA results

LDA	2021/2022 BRA	Scenario 3 and Scenario 4	Change	Percent
Rest of RTO	$140.00	$108.73	($31.27)	(22.3%)
Rest of MAAC	$140.00	$108.73	($31.27)	(22.3%)
Rest of EMAAC	$165.73	$155.00	($10.73)	(6.5%)
Rest of SWMAAC	$140.00	$108.73	($31.27)	(22.3%)
Rest of PSEG	$204.29	NA	NA	NA
PSEG North	$204.29	NA	NA	NA
DPL South	$165.73	$155.00	($10.73)	(6.5%)
Pepco	$140.00	$108.73	($31.27)	(22.3%)
Rest of ATSI	$171.33	$171.33	$0.00	0.0%
ATSI Cleveland	$171.33	$171.33	$0.00	0.0%
ComEd	$195.55	$195.55	$0.00	0.0%
BGE	$200.30	$200.30	$0.00	0.0%
PPL	$140.00	$108.73	($31.27)	(22.3%)
DAY	$140.00	$108.73	($31.27)	(22.3%)
DEOK	$140.00	$128.47	($11.53)	(8.2%)

Table 17 Net load charges for PSEG LDA (Scenario 3)

PSEG FRR	2021/2022 BRA	Scenario 3	Change	Percent
Zonal UCAP Obligation (MW UCAP)	10,901.1	10,445.6	(455.5)	(4.2%)
Zonal Capacity Price ($/MW-day)	$204.92	$244.24	$39.32	19.2%
Gross Load Charges	$815,342,184	$931,199,939	$115,857,755	14.2%
Value of CTRs	$83,093,233	$0	($83,093,233)	(100.0%)
Net Load Charges	$732,248,951	$931,199,939	$198,950,988	27.2%

Table 18 Net load charges for RTO excluding PSEG LDA (Scenario 3)

RTO (Excluding PSEG)	2021/2022 BRA	Scenario 3 and Scenario 4	Change	Percent
Zonal UCAP Obligation (MW UCAP)	152,726.2	153,516.8	790.6	0.5%
Gross Load Charges	$8,899,628,988	$7,946,819,327	($952,809,661)	(10.7%)
Value of CTRs	$245,033,264	$436,505,959	$191,472,695	78.1%
Net Load Charges	$8,654,595,724	$7,510,313,368	($1,144,282,356)	(13.2%)

Table 19 Net load charges for the Rest of New Jersey excluding PSEG (Scenario 3)

New Jersey (Excluding PSEG)	2021/2022 BRA	Scenario 3 and Scenario 4	Change	Percent
Zonal UCAP Obligation (MW UCAP)	9,667.0	9,717.0	50.0	0.5%
Gross Load Charges	$586,831,281	$551,848,868	($34,982,413)	(6.0%)
Value of CTRs	$11,399,731	$18,674,701	$7,274,970	63.8%
Net Load Charges	$575,431,550	$533,174,167	($42,257,383)	(7.3%)

Table 20 Change in load charges for PSEG, Rest of New Jersey and New Jersey (Scenario 3)

	PSEG		Rest of New Jersey		New Jersey	
	Change	Percent	Change	Percent	Change	Percent
Zonal UCAP Obligation (MW UCAP)	(455.5)	(4.2%)	50.0	0.5%	(405.5)	(2.0%)
Gross Load Charges	$115,857,755	14.2%	($34,982,413)	(6.0%)	$80,875,342	5.8%
Value of CTRs	($83,093,233)	(100.0%)	$7,274,970	63.8%	($75,818,263)	(80.2%)
Net Load Charges	$198,950,988	27.2%	($42,257,383)	(7.3%)	$156,693,605	12.0%

Scenario 4

In Scenario 4, an FRR is established for the PSEG LDA and the FRR procures the entire PSEG capacity obligation at a rate equal to the clearing price in the 2021/2022 RPM BRA ($204.29 per MW-day). The PSEG FRR has 4,494.0 MW UCAP or 43.0 percent fewer MW than needed to meet its FRR obligation. The PSEG FRR would need to contract with the owners of capacity resources outside the PSEG FRR to cover the deficit. If a PSEG FRR service area were created, the PSEG FRR would be required to procure 10,445.6 MW UCAP, 455.5 MW (4.2 percent) less than if the PSEG LDA remained in the PJM Capacity Market. In Scenario 4, summer capacity resources in the PSEG LDA are matched with winter capacity resources in the PSEG LDA such that the total annual equivalent price is less than or equal to the clearing price in the 2021/2022 RPM BRA ($204.29 per MW-day). The unmatched seasonal resources are mapped to the rest of EMAAC LDA.

Table 16 compares the clearing prices for the rest of the PJM Capacity Market by LDA for the 2021/2022 RPM BRA and for Scenario 4. All binding constraints would remain the same and the DEOK LDA constraint would also be binding. The Rest of RTO LDA clearing price would decrease by $31.27 per MW-day from $140.00 per MW-day to $108.73 per MW-day, or 22.3 percent, from the rest of the RTO LDA clearing price in the 2021/2022 RPM BRA. The EMAAC LDA clearing price would decrease by $10.73 per MW-day from $165.73 per MW-day to $155.00 per MW-day, or 6.5 percent, from the EMAAC LDA clearing price in the 2021/2022 RPM BRA. The DEOK LDA clearing price would decrease by $11.53 per MW-day from $140.00 per MW-day to $128.47 per MW-day, or 8.2 percent, from the DEOK LDA clearing price in the 2021/2022 RPM BRA.

The AECO Zone clearing price would decrease by $10.73 per MW-day from $165.73 per MW-day to $155.00 per MW-day or 6.5 percent from the AECO Zone clearing price in the 2021/2022 RPM BRA. The JCPL Zone clearing price would decrease by $10.73 per MW-day from $165.73 per MW-day to $155.00 per MW-day or 6.5 percent from the JCPL Zone clearing price in the 2021/2022 RPM BRA. The RECO Zone clearing price would decrease by $10.73 per MW-day from $165.73 per MW-day to $155.00 per MW-day or 6.5 percent from the RECO Zone clearing price in the 2021/2022 RPM BRA.

Table 21 shows the gross and net load charges to the PSEG FRR for the 2021/2022 BRA and for Scenario 4. The net load charges when the PSEG LDA is included in the PJM Capacity Market are net of CTR payments.

Table 21 shows that, based on actual auction clearing prices and quantities, make whole MW and RPM zonal UCAP obligation, gross load charges for the 2021/2022 RPM BRA for the PSEG LDA were $815,342,184. In the 2021/2022 RPM BRA, only 5,367.6 MW UCAP of PSEG capacity resources cleared. The PSEG LDA needed 5,533.5 MW UCAP to meet the PSEG zonal UCAP obligation. The CTR credits received by the PSEG LDA are based on the UCAP MW needed to meet the PSEG UCAP obligation. The PSEG LDA imported 6,902.0 MW of capacity from the Rest of the EMAAC LDA. The clearing price for the PSEG LDA was $38.56 per MW-day higher than the clearing price of the Rest of the EMAAC LDA. The load in the PSEG Zone received CTR credits of $83,093,233. After accounting for CTRs, the net load charges for the 2021/2022 RPM BRA for the PSEG LDA were $732,248,951.

If a PSEG FRR were created and the capacity price for the PSEG FRR were the clearing price in the BRA ($204.29 per MW-day), the load charges for the PSEG FRR would have been $778,884,849, an increase of $46,635,898, or 6.4 percent higher than in the 2021/2022 BRA.[50]

The higher load charges in Scenario 4 compared to the results of the 2021/2022 BRA are the result of the same clearing prices and the elimination of CTRs, which more than offsets the lower FRR UCAP obligation for the load in New Jersey. In the 2021/2022 RPM BRA, the load in the PSEG LDA received CTR credits of $83,093,233. Credits for CTRs do not exist with an FRR. CTR credits are based on the operation of an integrated capacity market with locational pricing.

In the 2021/2022 RPM BRA, the load in the PSEG Zone was charged for 10,901.1 MW UCAP, PSEG's share of the zonal unforced capacity obligation. If a PSEG FRR service area were created, the load in the PSEG Zone would need to procure 10,445.6 MW UCAP, the FRR UCAP obligation for the PSEG Zone.

Table 22 shows the net load charges, for the RTO excluding the PSEG LDA, for Scenario 4. The net load charges for the RTO excluding the PSEG FRR are the same as Scenario 3.

Table 23 shows the net load charges, for New Jersey excluding the PSEG LDA, for Scenario 4. The net load charges for New Jersey excluding the PSEG FRR are the same as Scenario 3.

Table 24 shows the change in the net load charges for PSEG, the rest of New Jersey and New Jersey. Under Scenario 4, the net load charges for PSEG would increase by 6.4

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50 The $204.92 per MW-day is the zone net load price, the capacity price charged to the load in the PSEG Zone. In the 2021/2022 BRA, the resource clearing price for the PSEG LDA was $204.29 per MW-day. The difference of $0.63 per MW-day was due to PSEG's portion of funding for cleared Price Responsive Demand (PRD) credits and make whole payments to the seasonal resources.

percent. The net load charges for New Jersey excluding the PSEG FRR would decrease by 7.3 percent. The net load charges for all of New Jersey would increase by 0.3 percent. The reduction in load charges for the rest of New Jersey due to the decrease in clearing prices in AECO, JCPL and RECO mostly offset the increase in the net load charges for the PSEG LDA.

If New Jersey were to subsidize any generating units, the subsidy costs would be in addition to the direct FRR costs.

Table 21 Net load charges for PSEG LDA (Scenario 4)

PSEG FRR	2021/2022 BRA	Scenario 4	Change	Percent
Zonal UCAP Obligation (MW UCAP)	10,901.1	10,445.6	(455.5)	(4.2%)
Zonal Capacity Price ($/MW-day)	$204.92	$204.29	($0.63)	(0.3%)
Gross Load Charges	$815,342,184	$778,884,849	($36,457,335)	(4.5%)
Value of CTRs	$83,093,233	$0	($83,093,233)	(100.0%)
Net Load Charges	$732,248,951	$778,884,849	$46,635,898	6.4%

Table 22 Net load charges for RTO excluding PSEG LDA (Scenario 4)

RTO (Excluding PSEG)	2021/2022 BRA	Scenario 3 and Scenario 4	Change	Percent
Zonal UCAP Obligation (MW UCAP)	152,726.2	153,516.8	790.6	0.5%
Gross Load Charges	$8,899,628,988	$7,946,819,327	($952,809,661)	(10.7%)
Value of CTRs	$245,033,264	$436,505,959	$191,472,695	78.1%
Net Load Charges	$8,654,595,724	$7,510,313,368	($1,144,282,356)	(13.2%)

Table 23 Net load charges for the Rest of New Jersey excluding PSEG LDA (Scenario 4)

New Jersey (Excluding PSEG)	2021/2022 BRA	Scenario 3 and Scenario 4	Change	Percent
Zonal UCAP Obligation (MW UCAP)	9,667.0	9,717.0	50.0	0.5%
Gross Load Charges	$586,831,281	$551,848,868	($34,982,413)	(6.0%)
Value of CTRs	$11,399,731	$18,674,701	$7,274,970	63.8%
Net Load Charges	$575,431,550	$533,174,167	($42,257,383)	(7.3%)

Table 24 Change in load charges for PSEG LDA, Rest of New Jersey and New Jersey (Scenario 4)

	PSEG		Rest of New Jersey		New Jersey	
	Change	Percent	Change	Percent	Change	Percent
Zonal UCAP Obligation (MW UCAP)	(455.5)	(4.2%)	50.0	0.5%	(405.5)	(2.0%)
Gross Load Charges	($36,457,335)	(4.5%)	($34,982,413)	(6.0%)	($71,439,748)	(5.1%)
Value of CTRs	($83,093,233)	(100.0%)	$7,274,970	63.8%	($75,818,263)	(80.2%)
Net Load Charges	$46,635,898	6.4%	($42,257,383)	(7.3%)	$4,378,515	0.3%

Scenario 5

In Scenario 5, an FRR is established for the JCPL and the FRR procures the entire JCPL capacity obligation at a rate equal to the 2021/2022 net CONE times B offer cap ($217.38

per MW-day). The JCPL LDA has 2,448.0 MW UCAP or 38.9 percent fewer MW than needed to meet its FRR UCAP Obligation. The JCPL FRR would need to contract with capacity resources outside the JCPL FRR to cover the deficit. If a JCPL FRR were created, the load in the FRR would be required to procure 6,295.9 MW UCAP, 242.6 MW (3.7 percent) less than if the JCPL LDA remained in the PJM Capacity Market. In Scenario 5, summer capacity resources in the JCPL LDA are matched with winter capacity resources in the JCPL LDA such that the total annual equivalent price is less than or equal to the 2021/2022 net CONE times B offer cap ($217.38 per MW-day). The unmatched seasonal resources are mapped to the rest of EMAAC LDA.

This is a sensitivity analysis based on the assumption that the owners of capacity resources in the JCPL FRR would request payment at the existing offer cap and that all capacity resources would be paid the same price. It is assumed that the actual price for capacity in the JCPL FRR would be the result of a negotiation between the owners of the required capacity, and the State of New Jersey. The price for capacity resources could substantially exceed the capacity market clearing price and the capacity market offer cap.

Table 25 compares the clearing prices for the rest of the PJM Capacity Market by LDA for the 2021/2022 RPM BRA and for Scenario 5. All binding constraints would remain binding and the DEOK LDA constraint would also be binding. The Rest of RTO LDA clearing price would decrease by $18.31 per MW-day from $140.00 per MW-day to $121.69 per MW-day, or 13.1 percent, from the Rest of RTO LDA clearing price in the 2021/2022 RPM BRA. The EMAAC LDA clearing price would increase by $8.81 per MW-day from $165.73 per MW-day to $174.54 per MW-day, or 5.3 percent, from the EMAAC LDA clearing price in the 2021/2022 RPM BRA. The PSEG LDA clearing price would increase by $24.68 per MW-day from $204.29 per MW-day to $228.97 per MW-day, or 12.1 percent, from the PSEG LDA clearing price in the 2021/2022 RPM BRA. The DEOK LDA clearing price would decrease by $11.53 per MW-day from $140.00 per MW-day to $128.47 per MW-day, or 8.2 percent, from the DEOK LDA clearing price in the 2021/2022 RPM BRA. The JCPL FRR would need to contract with resources in the rest of EMAAC and PSEG LDAs to meet its FRR Obligation. The reduced supply in the EMAAC and PSEG LDAs, which are constrained LDAs in the 2021/2022 RPM BRA, would result in higher clearing prices for EMAAC and PSEG.

The AECO clearing price would increase by $8.81 per MW-day from $165.73 per MW-day to $174.54 per MW-day or 5.3 percent from the AECO Zone clearing price in the 2021/2022 RPM BRA. The PSEG LDA clearing price would increase by $24.68 per MW-day from $204.29 per MW-day to $228.97 per MW-day, or 12.1 percent, from the PSEG LDA clearing price in the 2021/2022 RPM BRA. The RECO Zone clearing price would increase by $8.81 per MW-day from $165.73 per MW-day to $174.54 per MW-day, or 5.3 percent, from the RECO Zone clearing price in the 2021/2022 RPM BRA.

Table 26 shows the gross and net load charges for the JCPL FRR for the 2021/2022 BRA and for Scenario 5. The net load charges when the JCPL LDA is included in the PJM Capacity Market are net of CTR payments to load.

Table 26 shows that, based on actual auction clearing prices and quantities, make whole MW and RPM zonal UCAP obligation, gross load charges for the 2021/2022 RPM BRA for the JCPL LDA were $396,922,134. In the 2021/2022 RPM BRA, only 3,782.4 MW UCAP of JCPL capacity resources cleared. The JCPL LDA needed 2,756.2 to meet the JCPL zonal UCAP obligation. The CTR credits received by the JCPL LDA are based on the UCAP MW needed to meet the JCPL UCAP obligation. The EMAAC LDA, which includes the entire JCPL LDA, imported 9,000.0 MW of capacity from the rest of the MAAC LDA. The clearing price for the EMAAC LDA was $25.73 per MW-day higher than the clearing price of the rest of the MAAC LDA. The load in the JCPL Zone received CTR credits of $7,710,573. After accounting for CTRs, the net load charges for the 2021/2022 RPM BRA for the JCPL LDA were $389,211,561.

If a JCPL FRR were created and the capacity price for the JCPL LDA were the net CONE times B offer cap ($217.38 per MW-day), the load charges for the JCPL LDA would have been $499,541,588, an increase of $110,330,027, or 28.3 percent higher than in the 2021/2022 BRA.

The higher load charges in Scenario 5 compared to the results of the 2021/2022 BRA are the result of higher prices and the elimination of CTRs, which more than offset the lower FRR UCAP obligation for the load in JCPL.

Table 27 shows the net load charges for the RTO excluding the JCPL LDA for Scenario 5. Based on actual auction clearing prices and quantities, make whole MW and RPM zonal UCAP obligation, the gross load charges for the 2021/2022 RPM BRA, for the RTO excluding the JCPL LDA, were $9,318,049,038. After accounting for payments due to CTRs valued at $320,415,924, the net load charges for the 2021/2022 RPM BRA for the RTO excluding the JCPL LDA were $8,997,633,114.

If a JCPL FRR were created, the gross load charges for the 2021/2022 RPM BRA, for the RTO excluding the JCPL LDA would have been $8,961,093,954. After accounting for CTRs, the net load charges for the 2021/2022 RPM BRA, for the RTO excluding the JCPL FRR would be $8,478,946,024, a decrease of $518,687,090 or 5.8 percent.

Table 28 shows the net load charges for New Jersey excluding the load in the JCPL FRR for Scenario 5. Based on actual auction clearing prices and quantities, make whole MW and RPM zonal UCAP obligation, the gross load charges for the 2021/2022 RPM BRA, for New Jersey excluding the JCPL FRR were $1,005,251,331. After accounting for CTRs, the net load charges for the 2021/2022 RPM BRA for New Jersey excluding the JCPL FRR were $918,468,941.

Under Scenario 5, the gross load charges for the 2021/2022 RPM BRA, for New Jersey excluding the JCPL FRR would have been $1,116,668,314. After accounting for CTRs, the net load charges for the 2021/2022 RPM BRA, for New Jersey excluding the JCPL FRR would be $981,925,469, an increase of $63,456,528 or 6.9 percent.

Table 29 shows the change in the net load charges for JCPL, the rest of New Jersey and New Jersey. Under Scenario 5, the net load charges for JCPL would increase by 28.3 percent. The net load charges for New Jersey excluding the JCPL FRR would increase by 6.9 percent. The net load charges for New Jersey would increase by 13.3 percent. The increase in load charges for the rest of New Jersey due to the increase in clearing prices in the PSEG LDA and Rest of EMAAC LDA added to the increase in the net load charges for the JCPL LDA.

If New Jersey were to subsidize any generating units, the subsidy costs would be in addition to the direct FRR costs.

Table 25 Clearing prices in Scenario 5 compared to the actual BRA results

LDA	2021/2022 BRA	Scenario 5	Change	Percent
Rest of RTO	$140.00	$121.69	($18.31)	(13.1%)
Rest of MAAC	$140.00	$121.69	($18.31)	(13.1%)
Rest of EMAAC	$165.73	$174.54	$8.81	5.3%
Rest of SWMAAC	$140.00	$121.69	($18.31)	(13.1%)
Rest of PSEG	$204.29	$228.97	$24.68	12.1%
PSEG North	$204.29	$228.97	$24.68	12.1%
DPL South	$165.73	$174.54	$8.81	5.3%
Pepco	$140.00	$121.69	($18.31)	(13.1%)
Rest of ATSI	$171.33	$171.33	$0.00	0.0%
ATSI Cleveland	$171.33	$171.33	$0.00	0.0%
ComEd	$195.55	$195.55	$0.00	0.0%
BGE	$200.30	$200.30	$0.00	0.0%
PPL	$140.00	$121.69	($18.31)	(13.1%)
DAY	$140.00	$121.69	($18.31)	(13.1%)
DEOK	$140.00	$128.47	($11.53)	(8.2%)

Table 26 Net load charges for JCPL LDA (Scenario 5)

JCPL FRR	BRA	Scenario 5	Change	Percent
Zonal UCAP Obligation	6,538.6	6,295.9	(242.6)	(3.7%)
Zonal Capacity Price ($/MW-day)	$166.31	$217.38	$51.07	30.7%
Gross Load Charges	$396,922,134	$499,541,588	$102,619,454	25.9%
Value of CTRs	$7,710,573	$0	($7,710,573)	(100.0%)
Net Load Charges	$389,211,561	$499,541,588	$110,330,027	28.3%

Table 27 Net load charges for RTO excluding JCPL LDA (Scenario 5)

RTO (Excluding JCPL)	BRA	Scenario 5	Change	Percent
Zonal UCAP Obligation	157,088.7	157,521.2	432.5	0.3%
Gross Load Charges	$9,318,049,038	$8,961,093,954	($356,955,084)	(3.8%)
Value of CTRs	$320,415,924	$482,147,929	$161,732,005	50.5%
Net Load Charges	$8,997,633,114	$8,478,946,024	($518,687,090)	(5.8%)

Table 28 Net load charges for the Rest of New Jersey (Scenario 5)

New Jersey (Excluding JCPL)	BRA	Scenario 5	Change	Percent
Zonal UCAP Obligation	14,029.5	14,068.1	38.6	0.3%
Gross Load Charges	$1,005,251,331	$1,116,668,314	$111,416,983	11.1%
Value of CTRs	$86,782,390	$134,742,845	$47,960,455	55.3%
Net Load Charges	$918,468,941	$981,925,469	$63,456,528	6.9%

Table 29 Change in load charges for JCPL LDA, Rest of New Jersey and New Jersey (Scenario 5)

	JCPL		Rest of New Jersey		New Jersey	
	Change	Percent	Change	Percent	Change	Percent
Zonal UCAP Obligation	(242.6)	(3.7%)	38.6	0.3%	(204.0)	(1.0%)
Gross Load Charges	$102,619,454	25.9%	$111,416,983	11.1%	$214,036,437	15.3%
Value of CTRs	($7,710,573)	(100.0%)	$47,960,455	55.3%	$40,249,882	42.6%
Net Load Charges	$110,330,027	28.3%	$63,456,528	6.9%	$173,786,555	13.3%

Scenario 6

In Scenario 6, an FRR is established for the JCPL LDA and the FRR procures the entire JCPL capacity obligation at a rate equal to the clearing price in the 2021/2022 RPM BRA ($165.73 per MW-day). The JCPL LDA has 2,448.0 MW UCAP or 38.9 percent fewer MW than needed to meet its FRR UCAP Obligation. The JCPL FRR would need to contract with capacity resources outside the JCPL FRR to cover the deficit. If a JCPL FRR service area were created, the load in the service area would be required to procure 6,295.9 MW UCAP, 242.6 MW (3.7 percent) less than if the JCPL LDA remained in the PJM Capacity Market. In Scenario 6, summer capacity resources in the JCPL LDA are matched with winter capacity resources in the JCPL LDA such that the total annual equivalent price is less than or equal to the clearing price in the 2021/2022 RPM BRA ($165.73 per MW-day). The unmatched seasonal resources are mapped to the rest of EMAAC LDA.

Table 30 compares the clearing prices for the rest of the PJM Capacity Market by LDA for the 2021/2022 RPM BRA and for Scenario 6. All binding constraints would have remained binding and the DEOK LDA constraint would also be binding. The Rest of the RTO LDA clearing price would decrease by $16.39 per MW-day from $140.00 per MW-day to $123.61 per MW-day, or 11.7 percent, from the rest of the RTO LDA clearing price in the 2021/2022 RPM BRA. The EMAAC LDA clearing price would increase by $19.27 per MW-day from $165.73 per MW-day to $185.00 per MW-day, or 11.6 percent, from the EMAAC LDA clearing price in the 2021/2022 RPM BRA. The DEOK LDA clearing price would decrease by $11.53 per MW-day from $140.00 per MW-day to $128.47 per

MW-day, or 8.2 percent, from the DEOK LDA clearing price in the 2021/2022 RPM BRA. The JCPL FRR would need to contract with resources in the rest of EMAAC only to meet its FRR Obligation. In Scenario 6, the JCPL FRR would not contract with resources in the PSEG LDA. The capacity resources in the PSEG LDA would be paid more ($204.29 per MW-day) if they remained in the PJM Capacity Market than the FRR rate equal to the clearing price of the JCPL LDA in the 2021/2022 RPM BRA ($165.73 per MW-day). The reduced supply, which would be greater than the change in the demand curve, in the EMAAC LDA, a constrained LDA in the 2021/2022 RPM BRA, would result in a higher clearing price for EMAAC.

The AECO Zone clearing price would increase by $19.27 per MW-day from $165.73 per MW-day to $185.00 per MW-day or 11.6 percent from the AECO Zone clearing price in the 2021/2022 RPM BRA. The PSEG LDA clearing price would remain the same. The RECO Zone clearing price would increase by $19.27 per MW-day from $165.73 per MW-day to $185.00 per MW-day, or 11.6 percent, from the RECO Zone clearing price in the 2021/2022 RPM BRA.

Table 31 shows the gross and net load charges for the JCPL LDA for the 2021/2022 BRA and Scenario 6. The net load charges when the JCPL LDA is included in the PJM Capacity Market are net of CTRs.

Table 31 shows that, based on actual auction clearing prices and quantities, make whole MW and RPM zonal UCAP obligation, gross load charges for the 2021/2022 RPM BRA for the JCPL LDA were $396,922,134. In the 2021/2022 RPM BRA, only 3,782.4 MW UCAP of JCPL capacity resources cleared. The JCPL LDA needed 2,756.2 to meet the JCPL zonal UCAP obligation. The CTR credits received by the JCPL LDA are based on the UCAP MW needed to meet the JCPL UCAP obligation. The EMAAC LDA, which includes the entire JCPL LDA imported 9,000.0 MW of capacity from the rest of the MAAC LDA. The clearing price for the EMAAC LDA was $25.73 per MW-day higher than the clearing price of the rest of the MAAC LDA. The load in the JCPL Zone received CTR credits of $7,710,573. After accounting for CTRs, the net load charges for the 2021/2022 RPM BRA for the JCPL LDA were $389,211,561.

If a JCPL FRR were created and the capacity price for JCPL LDA were the clearing price in the BRA ($165.73 per MW-day), the load charges for the JCPL LDA would have been $380,849,330, a decrease of $8,362,231, or 2.1 percent lower than in the 2021/2022 BRA.[51]

51 The $166.31 per MW-day is the zone net load price, the capacity price charged to the load in the JCPL LDA. In the 2021/2022 BRA, the resource clearing price for the EMAAC LDA, which includes the entire JCPL LDA was $165.73 per MW-day. The difference of $0.58 per MW-day was due to JCPL's portion of funding for cleared Price Responsive Demand (PRD) credits and make whole payments to the seasonal resources.

The lower load charges in Scenario 6 compared to the results of the 2021/2022 BRA are the result of the same clearing prices and the lower FRR UCAP obligation for the load in the JCPL LDA and the elimination of CTR credits, which partially offsets the lower FRR UCAP obligation.

Table 32 shows the net load charges for the RTO excluding the JCPL FRR for Scenario 6. Based on actual auction clearing prices and quantities, make whole MW and RPM zonal UCAP obligation, the gross load charges for the 2021/2022 RPM BRA, for the RTO excluding the JCPL LDA, were $9,318,049,038. After accounting for payments due to CTRs valued at $320,415,924, the net load charges for the 2021/2022 RPM BRA for the RTO excluding the JCPL LDA were $8,997,633,114.

If a JCPL FRR were created, the gross load charges for the 2021/2022 RPM BRA, for the RTO excluding the JCPL LDA would have been $8,981,803,821. After accounting for CTRs, the net load charges for the 2021/2022 RPM BRA, for RTO excluding the JCPL FRR would be $8,564,303,530, a decrease of $433,329,584 or 4.8 percent.

Table 33 shows the net load charges, for New Jersey excluding the JCPL FRR, for Scenario 6. Based on actual auction clearing prices and quantities, make whole MW and RPM zonal UCAP obligation, the gross load charges for the 2021/2022 RPM BRA, for New Jersey excluding the JCPL FRR were $1,005,251,331. After accounting for CTRs, the net load charges for the 2021/2022 RPM BRA for New Jersey excluding the JCPL FRR were $918,468,941.

Under Scenario 6, the gross load charges for the 2021/2022 RPM BRA, for New Jersey excluding the JCPL FRR would have been $1,030,896,797. After accounting for CTRs, the net load charges for the 2021/2022 RPM BRA, for New Jersey excluding the JCPL FRR would be $955,603,259, an increase of $37,134,318 or 4.0 percent.

Table 34 shows the change in the net load charges for the JCPL FRR, the rest of New Jersey and New Jersey. Under Scenario 6, the net load charges for the JCPL FRR would decrease by 2.1 percent. The net load charges for New Jersey excluding the JCPL LDA would increase by 4.0 percent. The net load charges for New Jersey would increase by 2.2 percent.

If New Jersey were to subsidize any generating units, the subsidy costs would be in addition to the direct FRR costs.

Table 30 Clearing prices in Scenario 6 compared to the actual BRA results

LDA	2021/2022 BRA	Scenario 6	Change	Percent
Rest of RTO	$140.00	$123.61	($16.39)	(11.7%)
Rest of MAAC	$140.00	$123.61	($16.39)	(11.7%)
Rest of EMAAC	$165.73	$185.00	$19.27	11.6%
Rest of SWMAAC	$140.00	$123.61	($16.39)	(11.7%)
Rest of PSEG	$204.29	$204.29	$0.00	0.0%
PSEG North	$204.29	$204.29	$0.00	0.0%
DPL South	$165.73	$185.00	$19.27	11.6%
Pepco	$140.00	$123.61	($16.39)	(11.7%)
Rest of ATSI	$171.33	$171.33	$0.00	0.0%
ATSI Cleveland	$171.33	$171.33	$0.00	0.0%
ComEd	$195.55	$195.55	$0.00	0.0%
BGE	$200.30	$200.30	$0.00	0.0%
PPL	$140.00	$123.61	($16.39)	(11.7%)
DAY	$140.00	$123.61	($16.39)	(11.7%)
DEOK	$140.00	$128.47	($11.53)	(8.2%)

Table 31 Net load charges for JCPL LDA (Scenario 6)

	BRA	Scenario 6	Change	Percent
Zonal UCAP Obligation	6,538.6	6,295.9	(242.6)	(3.7%)
Zonal Capacity Price ($/MW-day)	$166.31	$165.73	($0.58)	(0.4%)
Gross Load Charges	$396,922,134	$380,849,330	($16,072,804)	(4.0%)
Value of CTRs	$7,710,573	$0	($7,710,573)	(100.0%)
Net Load Charges	$389,211,561	$380,849,330	($8,362,231)	(2.1%)

Table 32 Net load charges for RTO excluding JCPL LDA (Scenario 6)

RTO (Excluding JCPL)	BRA	Scenario 6	Change	Percent
Zonal UCAP Obligation	157,088.7	157,461.5	372.8	0.2%
Gross Load Charges	$9,318,049,038	$8,981,803,821	($336,245,217)	(3.6%)
Value of CTRs	$320,415,924	$417,500,290	$97,084,366	30.3%
Net Load Charges	$8,997,633,114	$8,564,303,530	($433,329,584)	(4.8%)

Table 33 Net load charges for the Rest of New Jersey (Scenario 6)

New Jersey (Excluding JCPL)	BRA	Scenario 6	Change	Percent
Zonal UCAP Obligation	14,029.5	14,062.8	33.3	0.2%
Gross Load Charges	$1,005,251,331	$1,030,896,797	$25,645,466	2.6%
Value of CTRs	$86,782,390	$75,293,538	($11,488,852)	(13.2%)
Net Load Charges	$918,468,941	$955,603,259	$37,134,318	4.0%

Table 34 Change in load charges for JCPL, Rest of New Jersey and New Jersey (Scenario 6)

	JCPL		Rest of New Jersey		New Jersey	
	Change	Percent	Change	Percent	Change	Percent
Zonal UCAP Obligation	(242.6)	(3.7%)	33.3	0.2%	(209.4)	(1.0%)
Gross Load Charges	($16,072,804)	(4.0%)	$25,645,466	2.6%	$9,572,662	0.7%
Value of CTRs	($7,710,573)	(100.0%)	($11,488,852)	(13.2%)	($19,199,425)	(20.3%)
Net Load Charges	($8,362,231)	(2.1%)	$37,134,318	4.0%	$28,772,087	2.2%