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November 23, 2020

VIA ELECTRONIC MAIL ONLY

Aida Camacho-Welch, Secretary
New Jersey Board of Public Utilities
44 South Clinton Avenue
Trenton, New Jersey 08625
Board.secretary@bpu.nj.gov

Re: Jersey Central Power & Light Company Post-Work Session Comments
Investigation of Resource Adequacy Alternatives
BPU Docket No. EO20030203

Dear Secretary Camacho-Welch:

On November 9, 2020, the Staff of the New Jersey Board of Public Utilities ("Board" or "BPU") hosted a work session in the above-referenced proceeding to discuss a Fixed Resource Requirement ("FRR") proposal (the "Proposal") made by Public Service Enterprise Group ("PSEG") and Exelon Corp. ("Exelon"). Jersey Central Power & Light Company ("JCP&L" or the "Company") appreciates the Board Staff hosting this meeting and allowing interested stakeholders to ask clarifying questions regarding the Proposal. As indicated in previous comments, JCP&L supports the Board's use of a comprehensive statewide analysis and collaborative process to evaluate New Jersey's options for its clean energy future. The Company commends the Board for utilizing a structured and methodical approach to this undertaking and looks forward to continuing its work with Staff and interested stakeholders to ensure that New Jersey's clean energy goals can be met while minimizing the risks and costs to the State's customers.

JCP&L supports the clean energy targets and environmental objectives included in New Jersey's Energy Master Plan and is invested in New Jersey's success in achieving those goals. At the same time, JCP&L's focus remains on making sure that the Company's customers will not be disproportionately impacted as a result of any FRR plan and on providing safe and reliable service at a just and reasonable price. In furtherance of those aims, JCP&L offers the following comments on the Proposal set forth by PSEG and Exelon in their Post-Technical Conference comments and the subsequent work session on November 9. JPC&L also attaches a report prepared by Charles River Associates ("CRA"), whom the Company has been working with to perform an analysis of various options available to New Jersey to meet its clean energy goals, including an analysis of the Proposal set forth by PSEG and Exelon.

I. There continues to be important technical questions about the Proposal that remain unanswered and other aspects of the Proposal's competitive procurement mechanism that demonstrate the difficulties of designing a practical and cost-effective FRR auction.

While PSEG and its consultant were able to answer many questions about the Proposal at the working session, there are many critical technical questions about the Proposal that must be resolved prior to the Board and interested stakeholders completing a full evaluation. Below are examples of several questions and/or issues that must be resolved to accurately understand how the Proposal will function and the potential costs, risks, and benefits of the Proposal.

- Will the Board administer the FRR plan and the auction, or will that fall to the utilities who ultimately have the PJM tariff obligation under an FRR?
- As between the utility, the supplier and end-use customers, what are the risks (such as Capacity Performance ("CP") penalties, contract risk, settlement risk, regulatory risk, etc.) and who is responsible for each category of risks of an FRR?
- What mechanism would need to be developed to address over/underpayment related to capacity prices that would have been paid by customers in the FRR zone but for the election of the FRR in that zone? Would that mechanism also be used for administration and/or risk premiums (CP penalties) put onto the utilities?
- How will the risks, costs or savings of an FRR be spread statewide if the FRR is in one territory only?
- With the expectation that current PJM market power rules would not be appropriate for the FRR, what rules would be proposed for market power mitigation?
    - How would those rules be developed?
    - Who would approve the methodology utilized?
    - Who would approve the contract with any independent market monitor entity supporting the process?
- If units that receive compensation from New Jersey choose not to participate in the FRR, how does that change the risks and costs to utility customers and to the FRR Entity?
- If there are no obligations for large units to participate in the FRR, is it advisable to select a zone smaller than the JCP&L zone?
- What are considerations associated with starting with a smaller utility as the FRR Entity and growing the FRR if needed in the future?
- If the FRR Entity cannot fully subscribe the generation capacity needed, what options are available?
- If resources accept a state subsidy, should there be a requirement put on those resources to accept a capacity commitment as part of an FRR?
    - Would new contracts be structured to include such a requirement?
    - Is it possible to modify existing contracts to include such a requirement?
- How will contracts be structured?
    - Who will sign the contract with generation owners?
    - Who is the ultimate authority on the contract?
    - What indemnification processes and provisions would need to be put in place?
    - Who will determine the length of the contracts?

- What guarantees will the state of New Jersey give to the FRR Entity regarding the timely recovery of costs from a capacity procurement perspective and CP penalty perspective?

In addition to these technical questions, the competitive procurement mechanism options put forth by PSEG and Exelon have several elements that raise concerns about implementation and cost impact. The Reliability Pricing Model ("RPM") Derivative Pricing Proposal entails two or three tiers of capacity procured on a locational basis at a percentage of the subsequent Base Residual Auction ("BRA") price. Though this proposal has some interesting and promising features, there are several shortcomings that should be identified and, if possible, addressed:

- **Practical implementation of clearing logic:** The Proposal suggests that Tier 2 resources would offer to accept up to 105% of the locational BRA price and the lowest cost set of resources on a percentage basis would then be selected for inclusion in the FRR Plan. There is no way, however, in advance of the BRA results, to know which set of resources this would be; simply selecting the lowest percentage offers may or may not ultimately yield a least-cost outcome. For example, assume that one resource each make offers from the Mid-Atlantic Area Council ("MAAC") and Eastern Mid-Atlantic Area Council ("EMAAC"), with the MAAC resource offering to accept 105% of the BRA price and the EMAAC resource offering to accept 100%. The auction would then presumably select the "lower cost" EMAAC resource. Should the BRA then produce an EMAAC price more than 5% higher than the MAAC price, the FRR procurement would then have erroneously selected the higher cost resource. Alternatively, if the Tier 2 procurement were to be premised on the fact that the subsequent BRA will produce EMAAC prices that are considerably higher than MAAC prices – and, therefore, will result in a MAAC resource being selected first regardless of the percentage offer – that too could prove problematic, as upward trends in the Capacity Emergency Transfer Limit ("CETL") for EMAAC reduce the likelihood that EMAAC continues to experience price separation.

- **Incentives for Tier 1 participation:** PSEG suggests that "[w]hile bidding into the FRR is voluntary, resources that face [risk of not clearing due to Minimum Offer Price Rule ("MOPR") mitigation] should not need any additional incentives to participate in the FRR procurement beyond being enabled to be paid for their capacity value consistent with other capacity resources." However, this presumption fails to account for actual incentives available to New Jersey preferred resources, like offshore wind, which receives incentives under New Jersey's Offshore Wind Renewable Energy Certificate ("OREC") program. ORECs provide a fixed income stream on a $/MWh basis to the qualifying resource, from which any wholesale revenues are netted. Thus, the OREC receiving resource would be indifferent to receiving capacity payments or not, as any such payments would simply be netted from guaranteed OREC revenue.[1] This also highlights that the purpose of the FRR election should be more about ensuring that *customers* are not

[1] Indeed, an OREC resource may be disinclined to voluntarily participate in the FRR procurement due to the burden of additional administrative processes and because of the potential exposure to CP penalties.

forced to make duplicative payments for capacity than about whether resources have the opportunity to receive compensation for their contribution to regional resource adequacy.

- **Incentives for Tier 2 participation:** A separate set of concerns exist for Tier 2 capacity under the Derivative Pricing Proposal. The primary issue relates to attracting sufficient participation. It is *likely but not guaranteed* that there is sufficient low-cost capacity available in MAAC and EMAAC to fulfill a JCP&L or an Atlantic Electric FRR (to provide two examples) with capacity offers (based on going forward costs) at or close to $0.00/MW-day. Such resources would have effectively been price takers in the BRA and should be willing to sell capacity at a large fraction of, or small premium to, the BRA price, whatever that price ends up being. However, it is possible that there would be a need for higher cost resources—*i.e*, resources with non-trivial avoidable going forward costs—to fulfill an FRR Plan. Given the challenges of forecasting capacity prices in PJM, participating in the FRR procurement under the Derivative Pricing Proposal would present considerable and likely unjustifiable risk for such resources. For example, a resource in EMAAC with an expected net going forward cost of $160/MW-day could offer to sell into the FRR procurement at 105% of the subsequent EMAAC clearing price in the BRA. In two of the past four delivery years, that resource would then have been obligated to sell capacity at a loss. Put another way, under the Proposal, resources have no way of accurately submitting offers that reflect their costs. This type of risk would probably lead to very limited participation by any resources with expected going forward costs close to the expected auction clearing price range. In turn, this could significantly narrow the pool of participating supply and increase the possibility that an FRR Entity experiences a shortfall based on a lack of participating capacity.

The other approach for procurement of capacity put forth in the Proposal, the "Sealed Bid Marginal Pricing Approach," calls for price-based offers, with prices set on a zonal basis as a function of the marginal clearing offer in each zone. This mechanism raises a different set of concerns related to incentives and outcomes, several of which are acknowledged by PSEG:

- **Offer incentives and auction outcomes:** The chief problem with this procurement design, as PSEG points out, is that "bidders that are not subject to the MOPR would be incentivized to submit offers near their expected RPM outcomes." First, forecasting BRA outcomes is highly inexact. As a result, it would be expected that FRR offerors would err above their forecast price to avoid committing to sell capacity at below-market rates. Second and relatedly, resources that would be price takers in the BRA would rationally want to offer in excess of the expected BRA price, as they will expect to clear in the BRA and would, therefore, view the FRR procurement as an opportunity to extract a premium price for capacity sales. Thus, it stands to reason that the prices that result from a Sealed Bid Marginal Pricing Approach to FRR procurement are likely to be higher than the BRA

price for a zone, and potentially considerably so.[2] This is concerning from a customer cost standpoint.

- **Pricing logic:** PSEG proposes to establish a price for each zone (MAAC and EMAAC) based on the marginal offer from the lowest cost set of offers from that zone. While it could be expected that this marginal offer would be higher in EMAAC than in MAAC, and higher in PSEG than in EMAAC, it is possible that would not be the case given a wide range of potential offer behavior as market participants formulate offers based on BRA price expectations plus some risk accounting. By chance, the marginal offer in MAAC could be higher than the marginal offer in EMAAC. Furthermore—presuming resources, particularly New Jersey's preferred resources, would be allowed to offer from the PSEG and PSEG-North Locational Deliverability Areas ("LDA")—such offers could end up coming from *only* MOPR'ed resources, and, therefore, be relatively low cost as those resources would want to be sure to clear in the FRR auction. Thus, a PSEG marginal price in the FRR procurement could wind up being lower than the EMAAC or MAAC prices, which would be inconsistent with underlying RPM market dynamics. A solution to both of these problems would be to clarify that each pricing zone in the FRR procurement could clear at a price no lower than that of its "parent" zone.

JCP&L offers the above considerations about the proposed procurement methodologies set forth in the Proposal not to challenge the notion that an FRR approach is a potential option for New Jersey, but, rather, to bring attention to the difficulties associated with designing a practical and cost-effective FRR auction, both specifically and generally. As an alternative to the Proposal and the approaches set forth therein, JCP&L offers an FRR procurement approach, developed by CRA and discussed below and in the attached report, that (while similar in concept) overcomes some of the potential problems that have been identified.

II. An FRR in JCP&L's service territory may or may not be the most cost-effective FRR option, depending on the Board's objectives.

JCP&L has been actively evaluating the various proposals submitted by stakeholders in this proceeding, including those proposals submitted by PSEG and Exelon. As noted above, in furtherance of this effort, JCP&L retained CRA to assist with its evaluation of PSEG and Exelon's prior proposal in this proceeding and the Proposal. As detailed in the attached report, CRA's analysis indicates that JCP&L's territory may or may not be the most cost-effective FRR option, depending on certain assumptions regarding whether the nuclear units in New Jersey clear the RPM auction and depending on New Jersey's ultimate goals in implementing an FRR.[3] CRA's analysis also introduces a range of non-cost criteria that should be considered when determining which approach New Jersey might take in electing the FRR Alternative.

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[2] Under the RPM Derivative Pricing Approach, prices are also likely to clear above the RPM price. Though, the presence of a cap significantly limits the potential severity of the premium that will be paid.

[3] CRA's assessment of cost is framed within the proposal put forward by Exelon and PSEG in its May 20, 2020, submission in this docket, which it referred to as the "Integrated FRR Procurement" approach. While PSEG and Exelon's most recent proposal appear to have changed somewhat, the key elements of the structure remain similar and the results of CRA's analysis should still hold.

As it relates to the FRR Alternative, CRA analyzed five FRR approaches across six principal criteria. The five approaches included three approaches wherein individual LDAs—JCP&L, PSE&G, or Atlantic City Electric Company ("ACE")—would elect the FRR Alternative, a case calling for the whole state to elect the FRR, and a case where a metered portion of each LDA would elect the FRR, called the "partial" FRR Alternative. CRA assessed each approach against: (1) the potential cost (savings) relative to continuing to participate RPM with the reformed MOPR rules; (2) the level of ongoing direct exposure to RPM pricing; and (3) administrative effort. Further considerations for each FRR approach focused on challenges associated with the process of procuring capacity to fulfill the FRR requirements, particularly for capacity in excess of the load from New Jersey sponsored resources—referred to as "residual capacity" in the Proposal—given the assumption that New Jersey sponsored resources will likely be used to fulfill a portion of the FRR requirement. These residual capacity-related criteria include: (4) the total cost uncertainty; (5) the level of concern over the exercise of market power; and (6) the ability to fulfill an FRR Plan using only clean energy resources while respecting capacity transfer constraints. CRA also addresses the potential to "right size" the FRR as well as to provide opportunities for incremental deployment of the FRR election.

CRA's findings do not indicate a clear recommended approach, but, instead, suggest the need for a balancing of factors if New Jersey makes a choice about moving forward with the FRR Alternative. In addition to the assessment of the tradeoffs of various approaches to a New Jersey FRR election, CRA's report also touches on a range of associated issues that will need to be addressed in any case. The Board has already been made aware of many of these issues via written comments and the discussions at technical meetings. They include, but are not limited to, the following:

- Whether or not procurement approaches will need to be modified for New Jersey preferred clean energy resources, and how such changes might be implemented from a procurement process and contract structure perspective;
- How capacity will be procured to fulfill he FRR Plan. In its report, CRA proposes a residual procurement auction design that is consistent with the incentives that will be faced by participating resources and concerns of the FRR Entity;
- The degree to which market power is expected to be an issue depending on the geography of the FRR Entity and participating resources. In its report, CRA provides a preliminary market power analysis for several cases and presents options for mitigation rules and processes;
- Identification of risk management concerns, particularly related to PJM's capacity performance rules. In its report, CRA presents several alternatives for allocating risks to suppliers and/or New Jersey ratepayers; and
- Treatment of administrative costs. The FRR Entity or Entities will incur administrative costs associated with implementing the FRR Alternative. These costs should be recoverable in a timely manner and should not be unduly burdensome on a subset of New Jersey customers.

Again, JCP&L offers these comments and alternative approaches not as a criticism of the Proposal or the potential for an FRR in New Jersey but rather as a means of bringing to the Board's

attention the potential difficulties that arise when attempting to craft a practical and cost-effective FRR Alternative. JCP&L welcomes any questions the Board may have regarding CRA's analysis and would welcome an opportunity to meet and discuss same.

III. The Board's authority to implement an FRR must be fully understood and vetted to mitigate risk to the FRR Entity and customers in the State.

As has been noted by many stakeholders in this proceeding, the PJM Reliability Assurance Agreement ("RAA") requires an entity electing the FRR Alternative to make such election for a minimum term of five delivery years.[4] The election must be made at least four months prior to the BRA for the first applicable delivery year and the "FRR Capacity Plan demonstrating the [FRR Entity's] commitment of Capacity Resources" must be submitted one month before the BRA.[5] To do this, the FRR Entity will need to enter into capacity agreements with generators years before the delivery of the capacity is required. In other words, once an entity has started down the path of choosing the FRR Alternative, there are many complications and risks associated with unwinding such a choice. This may cause substantial problems where, as here, there is a concern that legal challenges may either hinder a smooth transition to an FRR Alternative or (much worse) cause such a path forward to be reversed because it is found to be contrary to existing law.

Throughout this proceeding, many stakeholders have argued that the FRR Alternative may be inconsistent with New Jersey's Electric Discount and Energy Competition Act ("EDECA") and may require New Jersey either to pass new legislation or require the Board to find that the provision of capacity to customers is no longer a competitive service in the State.[6] While PSEG and Exelon have argued to the contrary and assert that the Proposal can be implemented without legislation, the arguments that the Board does not have authority to order or regulate rates under an FRR may have merit.

Under EDECA, the Board lacks authority to "regulate, fix, or prescribe the rates, tolls, charges, rate structures, rate base, or cost of service of competitive services."[7] Electric generation service, which includes the provision of retail energy and capacity to customers in the State, is a competitive service under EDECA for which the Board cannot "regulate the . . . cost of service."[8] While the Board is within its authority to regulate the cost of the utilities' default service supply of retail capacity as part of Basic Generation Service ("BGS") (as BGS is expressly exempted from being a competitive service under EDECA), as other parties have suggested as well, it is arguably unable to do so for capacity acquired by the FRR Entity in order to serve the customers of third-party suppliers.[9] As such, the Board's regulation of the FRR Entity's procurement of capacity provided to shopping customers in New Jersey may be subject to legal challenge. While it is not

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[4] PJM Reliability Assurance Agreement ("RAA"), Section 8.1.C.
[5] *Id.*
[6] *See, e.g.*, Rate Counsel's Response to Staff Request for Written Comments at 9-10 (May 20, 2020); *see also* Comments of the New Jersey Large Energy Users Coalition at 22 (May 20, 2020).
[7] N.J.S.A. 48:3-56(a).
[8] N.J.S.A. 48:3-56(a) and (b).
[9] Under PJM RAA, Section 8.D.8, an FRR Entity in a jurisdiction that has implemented retail choice "must include in its FRR Capacity Plan all load, including expected load growth, in the FRR Service Area, notwithstanding the loss of any such load to or among alternative retails LSEs."

possible to predict what the result of any such action would be (or the potential legal remedies if an FRR is found to be contrary to EDECA), the possibility for such challenges creates uncertainty and risk for the chosen FRR Entity. JCP&L respectfully encourages the Board to ensure that its regulatory authority to implement an FRR is fully understood and vetted up front in order to mitigate any potential risk to the FRR Entity and customers in the State.

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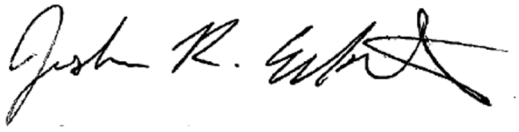
JCP&L again thanks the Board for the opportunity to provide this feedback and for its continued commitment to an open and transparent process while it continues to contemplate New Jersey's clean energy future. If you have any questions about these comments or the attached report prepared by CRA, please do not hesitate to contact me.

Respectfully submitted,



Joshua R. Eckert
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Assessment of FRR Alternatives: Considerations for New Jersey

November 23, 2020

CRA Charles River Associates

Prepared for:

Jersey Central® Power & Light
A FirstEnergy Company

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Objectives and Report Structure

- Ongoing reforms to the minimum offer pricing rule (MOPR) in PJM's capacity market (RPM), as required by FERC, threaten to drive over-procurement and increased costs to ratepayers due to duplicative procurement of capacity.
  - Some existing and most new state subsidized resources will effectively be precluded from having their capacity count towards regional resource adequacy requirements.
  - The resulting market distortions and additional customer costs are expected to be most acute in states with ambitious clean energy goals, like New Jersey.

- Several NJ stakeholders, including Exelon and PSEG, have suggested plans that would call for one or more NJ utilities to exercise the Fixed Resource Requirement (FRR) Alternative.
  - FRR is a provision of the PJM rules that allows LSEs to carve themselves out of PJM's capacity market and to satisfy their capacity procurement obligations on a self-supply basis.
  - Election of the FRR alternative allows the LSE, for a specified amount of load, to circumvent PJM's MOPR provisions and count state-subsidized capacity towards capacity obligations.

- This report is designed to support JCP&L in the understanding the economic and administrative considerations associated with an FRR election for the utility and its ratepayers.
  - We assess a range FRR Alternative options available to NJ utilities that would allow NJ ratepayers to avoid the negative effects of the PJM MOPR reforms.
  - We provide detailed quantitative and qualitative analysis of the FRR Alternative under a range of scenarios, including how varying FRR structures may affect NJ ratepayers from a cost and risk basis.
  - We identify issues of concern that may arise if FRR is elected and develop a "straw man" framework for the details of an FRR procurement structure that is responsive to those issues and will support cost effective outcomes for JCP&L customers.

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Alternative FRR Approaches: Summary of Findings

We summarize the pros and cons of various approaches ("scenarios") available to New Jersey in electing the FRR Alternative. We have modeled a range of scenarios and uncertainties within those scenarios. Combined with qualitative and quantitative consideration of other issues, we present our high level observations about each FRR scenario:

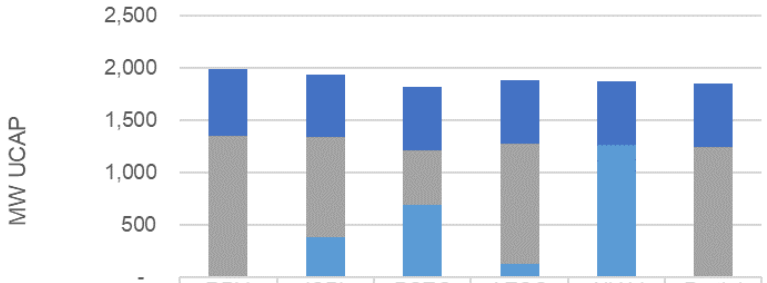
- **RPM Status Quo**: Declining to elect an FRR will likely lead to the highest aggregate customer cost owing to duplicative procurement, but would avoid administrative effort and uncertainty associated with implementing the FRR Alternative.
- **JCP&L Only FRR**: Low overall expected savings owing to high price PSEG zone remaining in RPM plus considerable residual capacity volumes. Lower uncertainty and market power issues in residual procurement due to avoiding CETL constraints. Likely to fulfill FRR Plan with only non-emitting resources. Benefit of phasing and gaining experience.
- **PSEG Only FRR**: Potential for highest level of savings due to removing high-price PSEG zone and large capacity demand from RPM. High level of cost uncertainty owing to high volumes of residual capacity and market power concerns, which will need to be mitigated. Not possible to fulfill PSEG FRR Plan with only non-emitting resources, so would include conventional resources. Benefit of phasing and gaining experience.
- **AECO Only FRR**: Moderate overall expected savings owing to high price PSEG zone remaining in RPM and right sizing residual volumes. Lower uncertainty and market power issues in residual procurement due to avoiding CETL constraints. Likely to fulfill FRR Plan with only non-emitting resources owing to both "right sizing" of obligation and large available pool of supply. Benefit of phasing and gaining experience.
- **All NJ FRR**: Potential for highest level of savings. Complete removal from RPM eliminates PJM price exposure, but increases uncertainty related to FRR procurement costs and high associated volumes. Owing to PSEG constraint and existing supply mix, market power would need to be addressed and conventional resources would be included in the FRR Plan.
- **Partial FRR**: Moderate overall expected cost owing to significant continued exposure to RPM prices in all NJ LDAs. Lower levels of uncertainty and market power issues in residual procurement due to very limited volume. High likelihood of being able to fulfill FRR Plan with only non-emitting resources. Extra administrative effort required to establish and maintain sub-metered zones within PJM requirements.

FRR Approach	Total NJ Cost Savings in Base Case	RPM Price Exposure	Administrative Effort	FRR Residual Capacity		
				Cost Uncertainty	Market Power Concerns	Only Clean Energy
RPM Status Quo	N/A	Highest	None	N/A	N/A	N/A
JCP&L FRR	Lowest	Moderate / High	Moderate	Moderate	Low	Likely
PSEG FRR	Highest	Moderate	Moderate	Higher	High	No
AECO FRR	Moderate	Moderate / High	Moderate	Lower	Low	Likely
All NJ FRR	Moderate	None	Moderate	Highest	Moderate / High (contains PSEG)	No
Partial FRR	High	High	Moderate / High	Lowest	Very low	Likely

FRR Modeling: Summary of Results

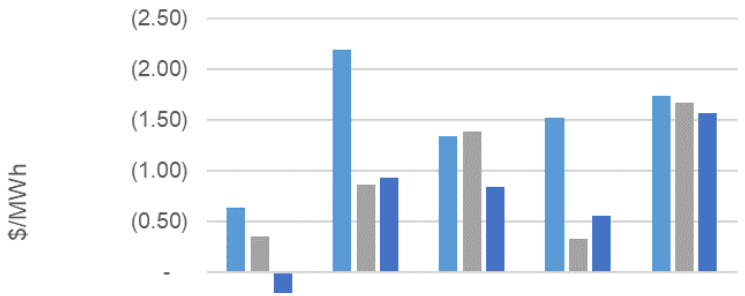
- CRA developed a model to quantify capacity and clean energy procurement costs under a framework proposed by PSEG and Exelon. Under our "base case" modeling assumptions, all FRR scenarios show a benefit to NJ ratepayer. Savings range from approximately $50-175M in the first year, with approximately 5-30% of savings accruing to JCP&L ratepayers depending on the case.
  - The JCP&L FRR scenario shows the least aggregate benefit.
  - We assess that the AECO and Partial FRR cases have the least uncertainty around the costs of procuring "residual capacity" – that is, capacity to fulfill the FRR Plan requirements in excess of NJ subsidized clean energy resources.
  - The PSEG FRR and All NJ scenarios have the most possible benefit if residual capacity costs are kept low, but also have the most uncertainty driven by residual capacity volumes, as the largest amount of residual capacity would be procured under these scenarios.
- Under base case assumptions, NJ ratepayers benefit as much or more than JCP&L ratepayers. JCP&L customers benefit less on a unit basis owing to having a lower average load factor than other NJ customers and therefore fewer MWh across which capacity costs may be allocated; they also do not benefit from reduced exposure to higher PSEG prices. However, as NJ subsidized volumes of generation grow over time, all benefit to a similar degree on a unit basis. None of these factors should be interpreted as an inequity in the underlying FRR framework design.
- All savings are presented on an annual basis and meant to represent savings tied to resources expected in service in the 2024/25 delivery year. Based on the Energy Master Plan, we expect the volume of affected resources to increase, and also therefore expect calculated savings to also increase over time.

Total Cost by Scenario



	RPM Case (Base)	JCPL FRR (Base)	PSEG FRR (Base)	AECO FRR (Base)	All NJ FRR (Base)	Partial FRR (Base)
All NJ Total Cost	1,993	1,942	1,816	1,885	1,870	1,853
Clean Energy Pmts.	644	603	603	603	603	603
RPM Cost	1,349	954	526	1,156	-	1,247
Res. Capacity Cost	-	386	687	127	1,267	3

Unit Savings by Scenario



	JCPL FRR (Base)	PSEG FRR (Base)	AECO FRR (Base)	All NJ FRR (Base)	Partial FRR (Base)
All NJ Unit Cost Change	(0.63)	(2.19)	(1.34)	(1.52)	(1.74)
JCPL Unit Cost Change	(0.35)	(0.86)	(1.39)	(0.32)	(1.67)
AECO Unit Cost Change	0.21	(0.93)	(0.84)	(0.55)	(1.57)

FRR Analysis: Discussion of Decision Drivers

- Based on our modeling results and sensitivity analysis, electing the FRR Alternative would be expected to result in reduced cost to New Jersey load under a wide range of scenarios – as compared with a "do nothing" BRA Case. Key drivers of uncertainty in our results include:
  - **Residual procurement cost outcomes**: The cost of procuring residual capacity is a considerable uncertainty, and the magnitude of the uncertainty varies with the volume of residual procurement in each scenario. Our analysis shows, however, that even under more pessimistic outlooks on residual procurement cost, electing the FRR would still lead to net savings or cost neutral outcomes for NJ customers.
  - **Combined Outcomes**: While not modeled explicitly, scenarios that include pessimistic outcomes for both residual procurement costs and other factors could result in net cost increases for NJ customers under an FRR election. We suggest that this should be weighed against (1) the near certainty of higher cost of maintaining the status quo, (2) the potential for nuclear compromises through advanced discussion with PSEG and Exelon, and (3) that residual procurement cost outcomes can be addressed through thoughtful procurement design (like the auction structure we have proposed). It is also highly relevant that the benefit of FRR election – and the cost of inaction – will increase considerably post-2024/25 as the total quantity of NJ subsidized supply grows.

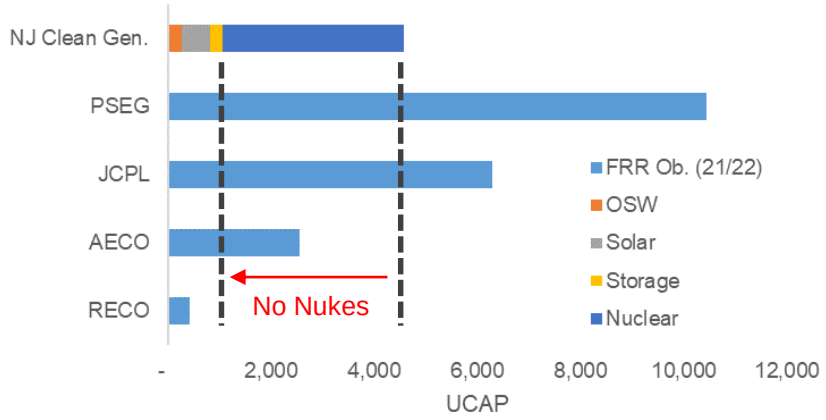
- Based on our assessment of the various FRR scenarios, we suggest the following logic could inform which scenario to support, depending on priorities and concerns:
  - Achieve FRR Plan with only non-emitting capacity → JCP&L FRR, AECO FRR, or Partial FRR
  - Maximize potential for total cost savings → PSEG FRR or All NJ FRR
  - Minimize residual capacity procurement cost / risk → Partial FRR (secondary: AECO FRR)
  - Minimize direct exposure to RPM prices going forward → All NJ FRR (secondary: PSEG FRR)
  - Minimize administrative complexity and market power concerns → JCPL FRR or AECO FRR
  - Incremental deployment of FRR structure → JCP&L FRR or AECO FRR or PSEG FRR

- We note that the JCP&L and AECO FRR approaches appear promising across a number of dimensions. In addition, both of these approaches allow for incrementalism and do not foreclose on an expanded FRR election if early results are encouraging. Of these two, AECO FRR has the larger modeled Base Case benefit owing to the better fit between NJ Clean Capacity and the FRR requirement.

FRR Entity Election: Right-Sizing Considerations

- The PSEG/Exelon proposal for an NJ FRR election suggests that JCP&L is the service territory that is best if seeking to match a single NJ utility service territory to volumes of current and expected future state-subsidized clean energy generation. The following reasons are given for suggesting FRR implementation starting with a single utility / LDA:
  - Allows for a phase-in of the FRR procurement structure over time, allowing opportunities for learning and limiting cost risk by limiting FRR volumes.
  - Selecting a zone without locational constraints (i.e., not PSEG) has benefits:
    - Avoid requirements about procuring from in-zone resources, thereby increasing competition and limiting market power concerns
    - Eliminates complications from needing to respect capacity transfer constraints in procurement process
  - Reduces need to compete with other FRR procurement, should other non-NJ utilities elect the FRR Alternative
  - To the extent that an LDA is selected that can source all residual capacity from non-emitting resources, limits perception that emitting energy resources are being procured (potentially at a premium) via state processes
- Given our understanding that both Salem and Hope Creek are expected to clear in the BRA – based on mitigation as a multi-unit plant for all three reactors – AECO may be a better fit than JCP&L if "right-sizing" is a priority.
- As clean energy requirements increase over time, additional EDCs could become FRR Entities to maintain the match between FRR demand and state-sponsored clean energy supply.

Comparison of NJ Clean Gen UCAP and FRR Obligations



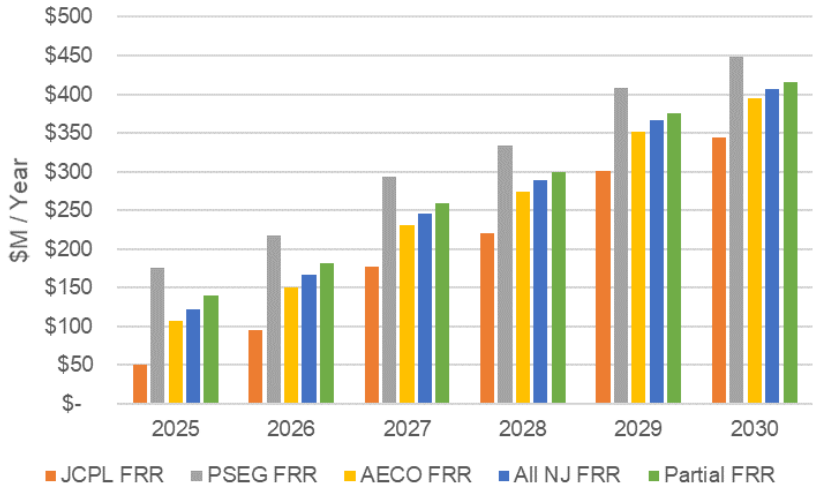
NJ Clean Gen (2025 Expected)

Clean Resource	ICAP MW	UCAP MW
Offshore Wind	1,100	282
Utility-Scale Solar	1,000	550
Storage	600	240
Nuclear: Salem	2,372	2,348
Nuclear: Hope Creek	1,172	1,160
Total	**6,244**	**4,580**

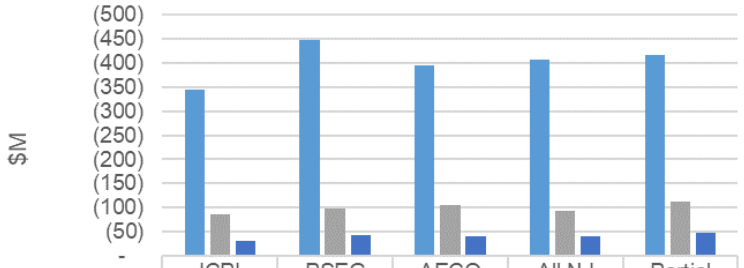
FRR Modeling: Longer Term Outlook

- The modeling analysis presented in this report focuses on results for the first delivery year (2024/25) in which NJ offshore wind will be online and excluded from selling capacity into RPM because of the revised MOPR rules.
- We have also developed a sensitivity analysis of how the results would change if quantities of subsidized (and MOPR'ed) wind and solar were increased as they are expected to under the NJ Energy Master Plan.
- As quantities of MOPR'ed clean energy capacity increase over time, the expected cost savings from electing the FRR increase across all modeled scenarios. This reflects the growth in duplicative capacity procurement as subsidized volumes increase (and associated effects). Thusly, conclusions about the FRR benefits become less ambiguous when looking across a longer time horizon.

Savings Under Increasing Quantities of Subsidized Wind and Solar

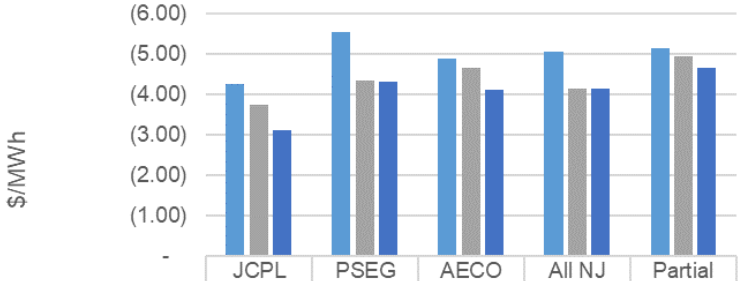


Total Savings (2030 CE Volumes)



	JCPL FRR	PSEG FRR	AECO FRR	All NJ FRR	Partial FRR
All NJ Cost Change	(344)	(448)	(394)	(407)	(415)
JCPL Cost Change	(86)	(99)	(107)	(95)	(113)
AECO Cost Change	(32)	(44)	(42)	(42)	(48)

Per Unit Savings (2030 CE Volumes)



	JCPL FRR	PSEG FRR	AECO FRR	All NJ FRR	Partial FRR
All NJ Unit Cost Change	(4.27)	(5.56)	(4.90)	(5.06)	(5.16)
JCPL Unit Cost Change	(3.75)	(4.35)	(4.67)	(4.14)	(4.96)
AECO Unit Cost Change	(3.12)	(4.33)	(4.13)	(4.14)	(4.67)

FRR Procurement Considerations: Summary of Findings

- Following the modeling analysis of the FRR scenarios, we have assessed further issues associated with procurement design under an FRR Alternative election. These issues would apply under any of the assessed scenarios. We make the following high level observations:
- **Clean Energy Procurement**: Contracting with offshore wind and utility-scale resources may be done on a competitive, bundled basis using long-term contracts. Contracting with nuclear resources, if done on a nuclear-specific basis, likely lends itself to cost-based remuneration.
- **Residual Capacity Procurement**: Resources participating in the residual capacity procurement to be included in an FRR Plan will face a novel set of incentives. We lay out a proposed auction design that is consistent with these incentives and will result in a cost effective outcome.
- **Market Power:** As with RPM, market power issues are likely to be an concern with residual capacity procurement, particularly if the constrained PSEG LDA is part of the FRR election. We present mitigation options should they be necessary.
- **Risk Management:** For resources included in the FRR Plan, the FRR Entity will be required by PJM to take on performance risk on their behalf. To ensure equitable exposure to such risk on the part of customers of the FRR Entity, we suggest several alternatives to, via contracts and regulatory arrangements, reallocate those risks to suppliers and/or all NJ ratepayers.
- **Timing Considerations:** There is a different MOPR-related risk profile for NJ ratepayers in the near term (pre-2024/25 delivery period) and long term (2024/25 and after) driven by clean energy generation CODs. This may inform how quickly New Jersey moves to implement an FRR, if it chooses to do so.
- **Reliability Impact:** Though mandated resource adequacy levels will be maintained, election of an FRR will technically lead to lower levels of reliability, all else equal, largely because inaction will result in over-procurement of capacity.
- **Administrative Cost:** While relatively small on the scale of costs being addressed throughout this report, the FRR Entity(s) will incur administrative cost associated with implementing the FRR Alternative. These cost should be recoverable in a manner that is not unduly burdensome on any subset of NJ customers.

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FRR Analysis: Discussion of Decision Drivers

- Based on our modeling results and sensitivity analysis, electing the FRR Alternative would be expected to result in reduced cost to New Jersey load under a wide range of scenarios – as compared with a "do nothing" BRA Case. Key drivers of uncertainty in our results include:
  - **Residual procurement cost outcomes**: The cost of procuring residual capacity is a considerable uncertainty, and the magnitude of the uncertainty varies with the volume of residual procurement in each scenario. Our analysis shows, however, that even under more pessimistic outlooks on residual procurement cost, electing the FRR would still lead to net savings or cost neutral outcomes for NJ customers.
  - **Combined Outcomes**: While not modeled explicitly, scenarios that include pessimistic outcomes for both residual procurement costs and other factors could result in net cost increases for NJ customers under an FRR election. We suggest that this should be weighed against (1) the near certainty of higher cost of maintaining the status quo, (2) the potential for nuclear compromises through advanced discussion with PSEG and Exelon, and (3) that residual procurement cost outcomes can be addressed through thoughtful procurement design (like the auction structure we have proposed). It is also highly relevant that the benefit of FRR election – and the cost of inaction – will increase considerably post-2024/25 as the total quantity of NJ subsidized supply grows.

- Based on our assessment of the various FRR scenarios, we suggest the following logic could inform which scenario to support, depending on priorities and concerns:
  - **Achieve FRR Plan with only non-emitting capacity** → JCP&L FRR, AECO FRR, or Partial FRR
  - **Maximize potential for total cost savings** → PSEG FRR or All NJ FRR
  - **Minimize residual capacity procurement cost / risk** → Partial FRR (secondary: AECO FRR)
  - **Minimize direct exposure to RPM prices going forward** → All NJ FRR (secondary: PSEG FRR)
  - **Minimize administrative complexity and market power concerns** → JCPL FRR or AECO FRR
  - **Incremental deployment of FRR structure** → JCP&L FRR or AECO FRR or PSEG FRR

- We note that the JCP&L and AECO FRR approaches appear promising across a number of dimensions. In addition, both of these approaches allow for incrementalism and do not foreclose on an expanded FRR election if early results are encouraging. Of these two, AECO FRR has the larger modeled Base Case benefit owing to the better fit between NJ Clean Capacity and the FRR requirement.

FRR Modeling: Summary of Findings

This section and the following explore details of various approaches ("scenarios") available to New Jersey in electing the FRR alternative. After describing the FRR rules and approach suggested by PSEG and Exelon, we model a range of scenarios and uncertainties within those scenarios. Combined with qualitative and quantitative discussion in the following section, we present our high level observations about each scenario:

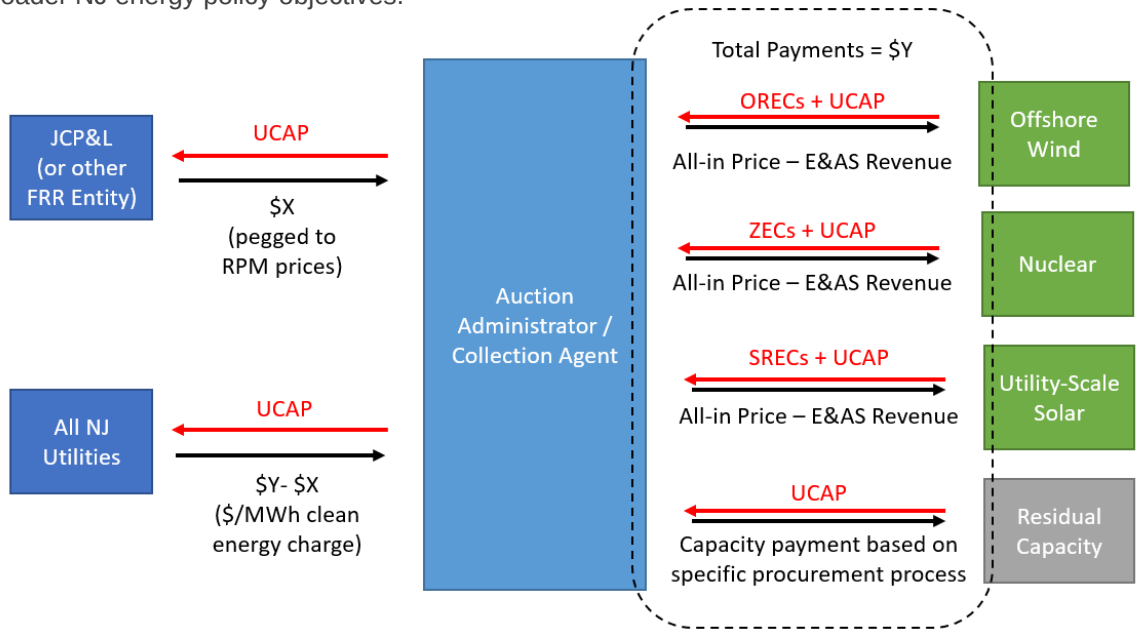
- **RPM Status Quo**: Declining to elect an FRR will likely lead to the highest aggregate customer cost owing to duplicative procurement, but would avoid administrative effort and uncertainty associated with implementing the FRR Alternative.
- **JCP&L Only FRR**: Low overall expected savings owing to high price PSEG zone remaining in RPM plus considerable residual capacity volumes. Lower uncertainty and market power issues in residual procurement due to avoiding CETL constraints. Likely to fulfill FRR Plan with only non-emitting resources. Benefit of phasing and gaining experience.
- **PSEG Only FRR**: Potential for highest level of savings due to removing high-price PSEG zone and large capacity demand from RPM. High level of cost uncertainty owing to high volumes of residual capacity and market power concerns, which will need to be mitigated. Not possible to fulfill PSEG FRR Plan with only non-emitting resources, so would include conventional resources. Benefit of phasing and gaining experience.
- **AECO Only FRR**: Moderate overall expected savings owing to high price PSEG zone remaining in RPM and right sizing residual volumes. Lower uncertainty and market power issues in residual procurement due to avoiding CETL constraints. Likely to fulfill FRR Plan with only non-emitting resources owing to both "right sizing" of obligation and large available pool of supply. Benefit of phasing and gaining experience.
- **All NJ FRR**: Potential for highest level of savings. Complete removal from RPM eliminates PJM price exposure, but increases uncertainty related to FRR procurement costs and high associated volumes. Owing to PSEG constraint and existing supply mix, market power would need to be addressed and conventional resources would be included in the FRR Plan.
- **Partial FRR**: Moderate overall expected cost owing to significant continued exposure to RPM prices in all NJ LDAs. Lower levels of uncertainty and market power issues in residual procurement due to very limited volume. High likelihood of being able to fulfill FRR Plan with only non-emitting resources. Extra administrative effort required to establish and maintain sub-metered zones within PJM requirements.

FRR Approach	Total NJ Cost Savings in Base Case	RPM Price Exposure	Administrative Effort	FRR Residual Capacity		
				Cost Uncertainty	Market Power Concerns	Only Clean Energy
RPM Status Quo	N/A	Highest	None	N/A	N/A	N/A
JCP&L FRR	Lowest	Moderate / High	Moderate	Moderate	Low	Likely
PSEG FRR	Highest	Moderate	Moderate	Higher	High	No
AECO FRR	Moderate	Moderate / High	Moderate	Lower	Low	Likely
All NJ FRR	Moderate	None	Moderate	Highest	Moderate / High (contains PSEG)	No
Partial FRR	High	High	Moderate / High	Lowest	Very low	Likely

PSEG/Exelon Proposed FRR Structure for New Jersey

General Framework

- PSEG and Exelon, in collaboration with The Northbridge Group, have developed a proposed FRR structure specific to the circumstances of New Jersey (schematic below).
  - Only one NJ utility (JCP&L, per their proposal) would elect the FRR, ostensibly to "right size" the FRR election to match volumes of NJ preferred generation.
  - An auction administrator (likely the NJBPU) would run the procurement to fulfill the FRR obligation, purchasing bundled clean energy products (including capacity) from each favored technology types in the mandated quantities ($Y below), as well as "residual capacity" from other (likely existing) resources to fulfill any remaining obligation.
  - Other the other NJ utilities would continue to participate in RPM on a business-as-usual basis.
- The proposed payment structures within this scheme aim to maintain equities between the FRR Entity's customers and other NJ customers
  - JCP&L customers would ultimately pay a capacity price referenced to BRA outcomes ($X total below), which we model as equal to the weighted average capacity cost paid by load (i.e., including CTR adjustments) in the non-FRR EMAAC LDAs of New Jersey.
  - All payments in excess of $X (i.e., $Y-$X) would be socialized across all NJ customers, reflecting the fact that those costs were incurred to achieve broader NJ energy policy objectives.



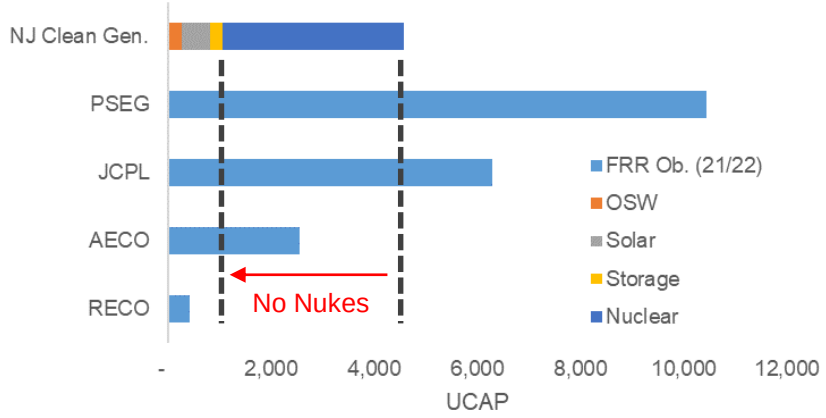
* *Source*: Developed based on PSEG / Exelon / Northbridge Proposal

PSEG/EXC Proposed FRR Structure for New Jersey

Right Sizing and FRR Entity Selection

- The proposed FRR arrangement for NJ suggests that JCP&L is the service territory that is best if seeking to match a single NJ utility service territory to volumes of current and expected future state-subsidized clean energy generation. The following reasons are given:
  - Allows for a phase-in of the FRR procurement structure over time, allowing opportunities for learning and limiting cost risk by limiting FRR volumes.
  - Selecting a zone without locational constraints (i.e., not PSEG) has benefits:
    - Avoid requirements about procuring from in-zone resources, thereby increasing competition and limiting market power concerns
    - Eliminates complications from needing to respect capacity transfer constraints in procurement process
  - Reduces need to compete with other FRR procurement, should other non-NJ utilities elect the FRR Alternative
  - To the extent that an LDA is selected that can source all residual capacity from non-emitting resources, limits perception that emitting energy resources are being procured (potentially at a premium) via state processes
- Given our understanding that both Salem and Hope Creek are expected to clear in the BRA – based on mitigation as a multi-unit plant for all three reactors – AECO may be a better fit than JCP&L if "right-sizing" is a priority.
- As clean energy requirements increase over time, additional EDCs could become FRR Entities to maintain the match between FRR demand and state-sponsored clean energy supply.

Comparison of NJ Clean Gen UCAP and FRR Obligations*



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* **Note**: FRR UCAP obligations are from 21/22 delivery period. PJM forecasts 2-4% growth between 21/22 and 24/25 delivery period, so owing to limited growth any observations from older vintage data should hold going forward.

PSEG/EXC Proposed FRR Structure for New Jersey

Capacity Procurement Structure

As proposed, the FRR procurement administrator (likely the NJBPU), would procure capacity in two tiers:

Tier 1: NJ Supported Resources Subject to MOPR

- Tier 1 resources would be procured first in an attempt to fill as much of the FRR Obligation UCAP with resources subject to MOPR mitigation.
- Award for selected resource would be long-term set price for the bundled energy, A/S, capacity, and clean attributes.
  - Increases certainty and decreases risk for both buyer and sellers
- Ultimate payments would be net of future market revenues.
- Wind and solar procurements – and any other state supported technology targets – would be constrained by not-to-exceed prices to balance state preferences with affordability concerns.
- Procurement order as follows:
  - Target quantity OSW
  - Target quantity of utility-scale solar
  - Remaining quantity, consistent with EMP, procured from additional wind, solar, or nuclear units subject to a lower not-to-exceed price

Tier 2: Residual Procurement

- Tier 2 resources procured after Tier 1 procurement, in sufficient quantity to fulfill FRR Obligation.
  - Preferred suppliers (Tier 2a) would include “nuclear, hydro, renewable generation, and other clean technology types recognized in New Jersey’s Class I RPS program, as well as demand response and energy efficiency resources located in EMAAC and, to the extent possible, MAAC.”
  - If necessary, further supply (Tier 2b) would be procured from gas-fired resources.
- Procurement process would be conducted annually, ahead of deadline for reporting FRR plan to PJM.
- Resulting contracts would be for one-year contracts for capacity only, consistent with PJM’s UCAP definition.
- Resources would be compensated on a pay-as-bid basis.

General Assessment of PSEG/EXC Proposed FRR Structure

- The proposed FRR framework, in our assessment, appears to achieve a range of objectives necessary in a plan for NJ to respond to the MOPR reforms being implemented by PJM:
  - ☑ Allows for NJ state-subsidized resources to be counted appropriately towards resource adequacy in a manner that does not lead to duplicative procurement and unwarranted costs for NJ ratepayers.
  - ☑ Creates a structure that should facilitate achievement of goals put forth in the NJ Energy Master Plan.
  - ☑ Procures sufficient capacity to meet obligations under the RAA.
  - ☑ Establishes what appears to be an equitable sharing of costs (for capacity and clean energy) that allocates excess cost – incremental to what would have been experienced should the FRR Entity have purchased via the BRA – to all NJ customers and not just those of the FRR Entity.

- Despite our concurrence that the proposed framework achieves high level objectives, further analysis is required to support any qualitative assertions on certain topics, in particular:
  - What are actual expected benefits and monetary flows associated with the proposed framework, and particularly with selecting JCP&L as the first FRR Entity?
  - And are the ultimate outcomes equitable for consumers both within and without of the FRR Plan?
  - Is there sufficient supply available in the residual (Tier 2) procurement – accounting for transmission constraints – and what kinds of market power issues might arise?

- There is also further consideration warranted regarding procurement design, risk allocation, implementation timing, and reliability implications.

The remainder of this report attempts to address these outstanding issues in more depth and, where appropriate, suggests alternatives to the framework developed by PSEG, Exelon, and Northbridge. Particular focus is paid to whether conclusions about the “goldilocks” nature of JCP&L’s territory for FRR are appropriate, and how to avoid circumstances that are unduly burdensome on JCP&L and its ratepayers.

FRR Model: Description and Cases Considered

- To perform this analysis, we developed a modeling tool to calculate and illustrate the costs and financial flows that would result from the proposed FRR framework under various cases.
- The particular focus is on the absolute and per unit impact on NJ ratepayers in general, and JCP&L customers in particular. This version of the model focuses on the differences between:
    1. The BRA outcome as the "status quo", accounting for the price and cost impact of the failure to recognize capacity value of MOPR'ed resources
    2. Alternative formulations (cases in box to right) of the FRR election for NJ utilities

Modeled FRR Scenarios

JCP&L Only FRR

PSEG Only FRR

AECO Only FRR

All NJ FRR

Partial FRR*

- CRA's model does not attempt to forecast RPM outcomes on a fundamentals basis. Rather, we ask:

"If the new market rules were in place for the 21/22 delivery period – and with levels of clean energy targeted for 2024/25 – how might the price and cost outcomes have unfolded in the modeled scenarios?"

- The model relies on publicly available information related particularly to the 2021/22 BRA and delivery period, including:
    - BRA auction parameters and results
    - PJM scenario analysis of the 2021/22 BRA (September 4, 2018)
    - IMM analysis of "Potential Impacts of the Creation of New Jersey FRRs" (May 13, 2020)
    - Public sources on estimated renewables costs and current subsidy arrangements

* **Note**: In the "Partial" FRR case, each NJ LSE elects the FRR Alternative for a portion of its load on a pro rata basis to peak load shares, for a total FRR election approximately equivalent to the quantity of MOPR'ed capacity

FRR Model: Reflected Market Dynamics

Overview

There are numerous market dynamics and rule provisions that are relevant to a calculation of the price and cost impact under the Status Quo and FRR cases. CRA's model attempts to reflect the following dynamics – if imperfectly – which are described individually in more detail on the following slides:

- Payments to New Jersey clean energy and FRR resources
  - Costs to load include the cost of subsidies and any other out-of-market payments to support state-preferred resources, which we assume are made whole should they lose capacity market revenues.
  - Under FRR scenarios, residual capacity in the FRR plan is procured at a premium to the BRA price.

- RPM Prices
  - Under the status quo, prices rise and volumes decline to reflect MOPR mitigation of existing resources and their exclusion from the counting as capacity within RPM.
  - Under FRR scenarios, removal of FRR LDA and associated capacity impacts BRA prices by (1) shifting VRR curve (2) removing capacity supplied in the FRR plan from the BRA supply curve and (3) by "freeing up" some capacity to participate in the BRA relative to a scenario in which there was no FRR elected and the FRR LDA's demand was included .
  - Under FRR scenarios, all else equal, increased capacity from subsidized clean energy resources increases aggregate supply counted towards RA, thus decreasing price.

- Cost to Load
  - Under FRR scenarios, CTR benefits to NJ load are modified to reflect changing price conditions and the fact that FRR LDAs do not receive CTR credits.
  - Load growth between 21/22 and 24/25 delivery periods (reflected in volumes but not price).

Any consideration of the costs and benefits of electing the FRR Alternative should include at least these dynamics.

Additional Model Design Notes

- Owing to limited detail about subsidy design and challenges associated with forecasting operational expectations, CRA's modeling **does not** consider energy storage deployment targets or costs. This will lead our results to be conservative, as a category of technology and associated duplicative procurement is not accounted for. We estimate that considering energy storage could lead to a potentially considerable increase in savings from an FRR election in the 2025 study year.

- Where we rely on the IMM's NJ FRR scenarios for the JCP&L FRR case, we use Scenario 6 and not Scenario 5 as a reference. Scenario 5 assumes unrealistically high prices offered to FRR resources, which skews results.

FRR Model: Reflected Market Dynamics

Payments to New Jersey Preferred Resources

- Modeling cost of alternative capacity procurement arrangements requires assumptions about compensation for state-preferred resources. We work from the general presumption that payments will be structured to achieve the goals of the NJ Energy Master Plan, which requires making resources whole in the absence of an expected capacity payment.
  - Status quo case (RPM only): subsidized resources that are excluded from receiving capacity revenues owing to the MOPR reforms are made whole at price levels equivalent to what they would have received via RPM.
  - FRR scenarios: subsidized resources receive payments at negotiated levels approximately equal to publicly-sourced cost-based estimates for plant operation.
- Where necessary, total payments to state-preferred resources are based on publicly available technology cost estimates, standard ancillary service revenue expectations, and energy margin outlook based on current market forwards.

Technology	Status Quo	FRR Scenarios	Comments
Offshore Wind	Total Resource Payment = $100 / MWh All market revenues netted from OREC compensation		OREC procurement structure does not appear to need adjustment to account for alternative NJ capacity arrangements. All revenue streams accounted for.
Utility-Scale Solar	Payment = current Tier 1 REC price (~$10 / MWh) + historical avg. EMAAC price ($174 / MW-day)	Payment = LCOE estimate - calculated forward energy margins	Assumes procurement and contract structure similar to that in place for OSW/ORECS Utility scale LCOE estimate = $36 / MWh (sensitivity presented in later slides) *Sources*: EIA, NREL, LBNL, Lazard
Nuclear	Payment = current ZEC price (~$10 / MWh) + historical avg. EMAAC price	No change from Status Quo	In FRR cases, nuclear resources do not participate in FRR Plan on basis different from other existing resources in RPM

FRR Model: Reflected Market Dynamics

Setting Prices for Residual Capacity

- To calculate total FRR costs, some assumption must be made about the costs of residual capacity necessary to fill FRR obligation in excess of NJ state-preferred clean energy capacity.
- In CRA's modeling, we assume that some premium payment will be required to incent eligible resources to participate in the NJ residual capacity procurement process. For each scenario in our "base case" (i.e., the case that employs our default assumptions) results, we assume that the calculated EMAAC price is the reference and a premium is calculated to reach payment levels approximately consistent with historical BRA outcomes.
  - Approximates conditions that we estimate will incent participation, particularly where volumes are expected to be low and procurement does not face issues with transmission constraints
  - Approximates conditions that will ensure economics of sufficient UCAP volumes to meet procurement obligations
- Note that this representation of residual capacity costs somewhat different from the procurement structure we propose later. We expect that the modeled approach will overstate costs relative to the proposed procurement design.

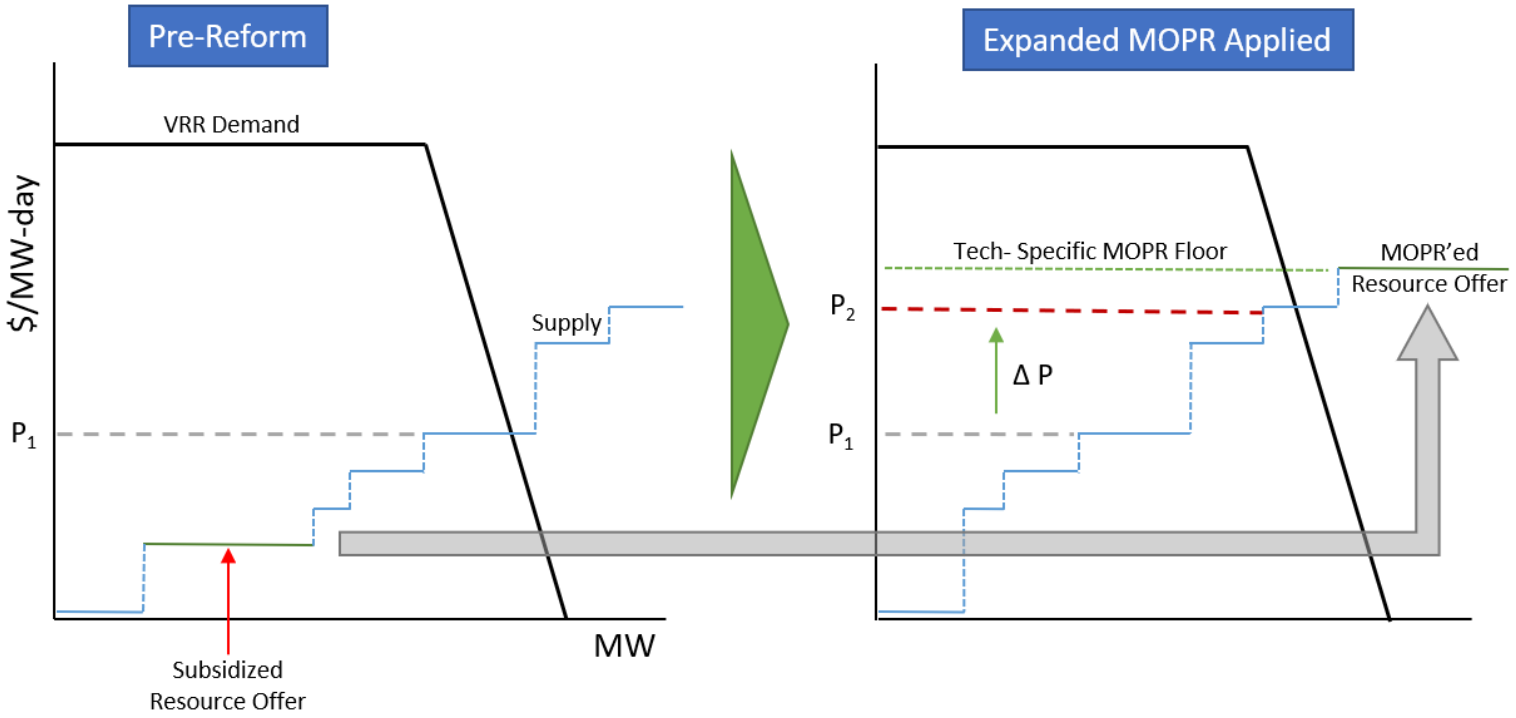
Scenario	Calculated EMAAC Price	Base Case Premium	Base Case Res. Cap. Price	Comments
JCP&L Only	$180	5%	~$189	Premium formulated for incentive to participate
PSEG Only	$150	25%	~$189	Premium formulated to ensure sufficient economic supply
AECO Only	$171	5%	$180	Premium formulated for incentive to participate
All NJ	$123	45%	$178	Premium formulated to ensure sufficient economic supply
Partial FRR	$161 PSEG: $194	5%	$170 PSEG: $204	Premium formulated for incentive to participate

This set of assumptions is a major driver of results, and sensitivities are presented following the base case results. Further issues of residual capacity procurement design are also discussed later.

FRR Model: Reflected Market Dynamics

Impact of MOPR Mitigation on Status Quo RPM

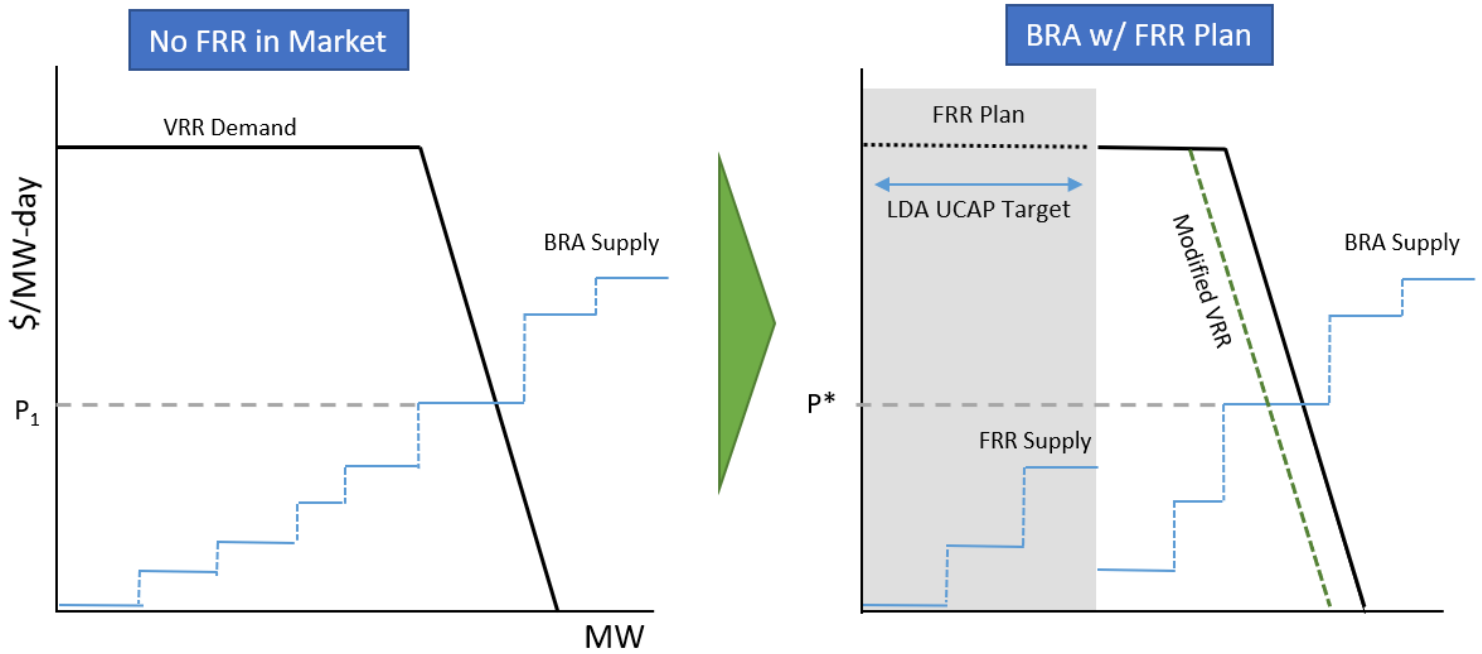
- For some scenario cases, our modeling reflects the exclusion of certain subsidized, existing resources from clearing in the BRA:
  - Under the expanded MOPR rules, a subsidized resource that was previously inframarginal would be required to offer at a mitigated minimum price, which would likely move it higher on the supply curve.
  - For certain technology types, the MOPR floors would be sufficiently high to preclude the mitigated offer from clearing, which would ultimately have the effect of raising expected prices (P1 → P2 below).
- Based on initial expectations for net ACR levels for existing resources, and the fact that Salem and Hope Creek will be treated as a single multi-unit resource, we expect that neither resource will be thusly excluded in the base case.
- CRA has relied on scenario analysis performed by PJM after the 2021/22 BRA to inform this calculated price effect under certain scenarios outside the base case.



FRR Model: Reflected Market Dynamics

Impact of FRR Alternatives on BRA Prices

- Should an LDA (or multiple LDAs) elect the FRR alternative, both supply and demand in the BRA are affected:
  - The VRR curve shifts to reflect removal of capacity demand associated with the FRR LDA. Aggregate procurement targets decline given that FRR procurement requirements are expected to be lower (in IRM terms) than what the BRA procures. All else equal, this should reduce expected prices.
  - Available supply shifts depending on which capacity resources are included in the FRR plan and how those resources would have offered (and cleared or not) in the BRA, as well as whether or not those resources are inside or outside of transmission constraints.
- The expected result of the above forces on prices (P* below) is ambiguous, and an FRR may increase or decrease expected BRA prices depending on the relative magnitude of contributing factors.
- CRA has relied on scenario analysis provided by the IMM to inform the effect of various FRR options on BRA prices.

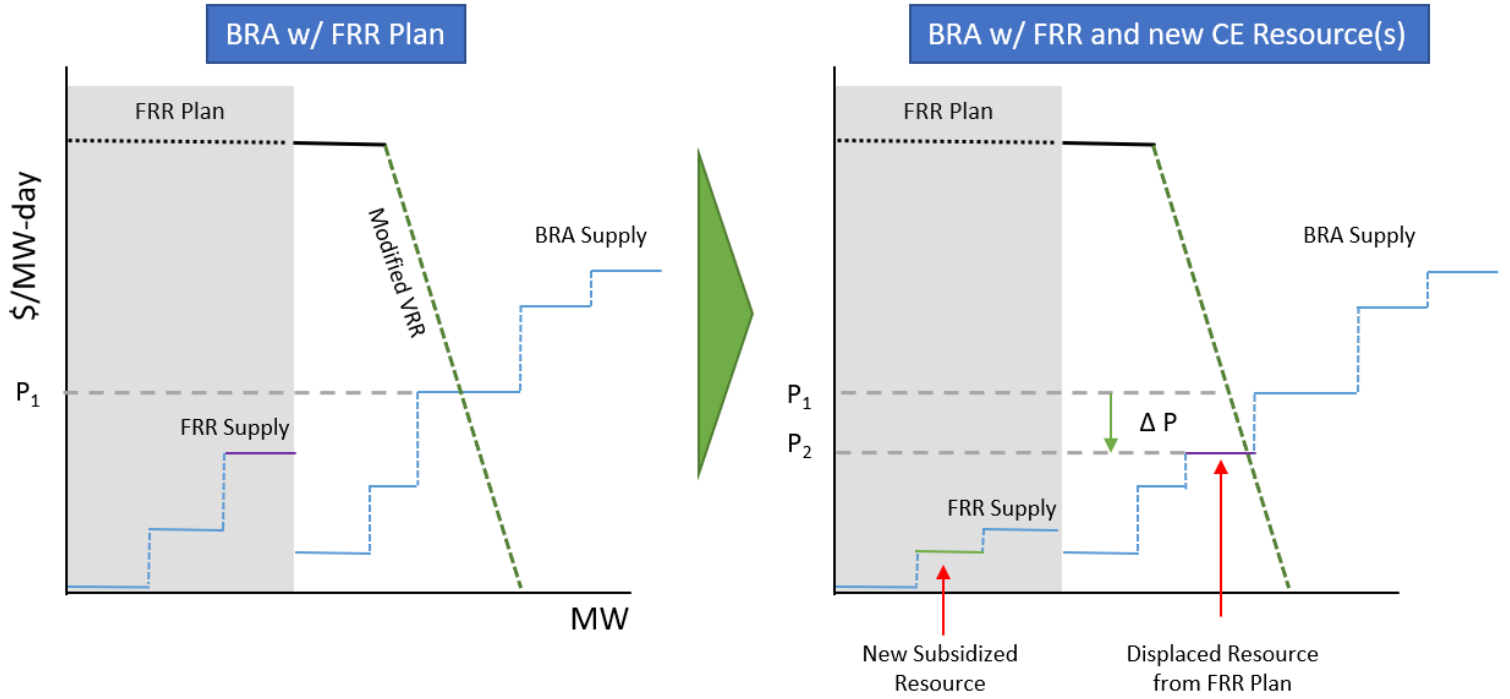


Note: the shown example assumes that only inframarginal resources are included in the FRR plan and that the ultimate result is that the BRA price stays the same. Neither of these results is necessary under an FRR scenario, and in particular it is likely that additional, potentially new resources (e.g., state preferred resources) will be included in the FRR plan (see next slide)

FRR Model: Reflected Market Dynamics

Impact of Subsidized Resources (in FRR) on BRA Prices

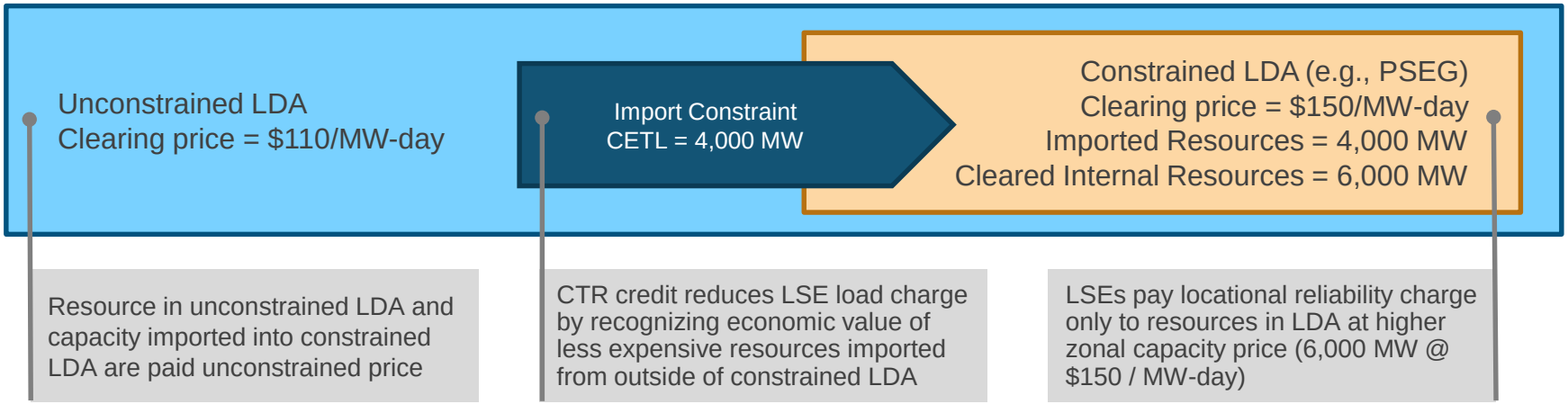
- Under the expected MOPR reforms, without participating in an FRR, most new subsidized resources are expected to have their capacity offers mitigated to such a level at which they will not be expected to clear.
- Participating in an FRR plan will allow such resources to contribute to the FRR entity's resource adequacy requirement, and therefore to PJM's accounting for resource adequacy for the broader market.
- By increasing aggregate capacity supply in the market, all else equal the capacity price would be expected to decline (P1 → P2 below).
- This can be conceptualized as the new subsidized resource displacing existing resources from an LDA's FRR plan that would otherwise have been required to fulfill capacity procurement obligations under the RAA.
- CRA has relied on scenario analysis performed by PJM after the 2021/22 BRA to inform this calculated price effect.



FRR Model: Reflected Market Dynamics

Capacity Transfer Rights

- The RPM market design incorporates Capacity Transfer Rights (CTRs), loosely analogous to FTRs in energy markets:
  - CTRs support balance of capacity market payments because only resources in constrained zone are paid the higher price, while also allocating value of transmission capability to the holders of the CTRs.
  - Most CTRs are allocated to LSEs, though they may also be allocated to merchant or participant-funded projects.
- CTRs ultimately reduce the capacity price observed by load, as load pays the zonal capacity price *less* the CTR credit rate for that zone for that BRA (e.g., in the 2021/22 BRA, the PSEG capacity price was $204/MW-day but the zonal net load price was $184/MW-day).
- When considering the cost to load of alternative scenarios, as is the goal of the this analysis, accounting for CTRs is a necessary and important element of assessing ultimate capacity costs to ratepayers. Impacts of price changes on load are ultimately muted by CTRs. Thus, CRA's model accounts for changes in CTR credits that reflect variation in market prices across scenarios, though we do not attempt to precisely capture (less impactful) changes in CTR volumes.
- The below shows a simplified, hypothetical example of how CTR credits function:
  - The constrained LDA experiences a higher price owing to capacity import constraints
  - Within the constrained LDA, 6 GW of internal resources would receive the higher capacity price
  - The 4 GW of resources imported from the unconstrained LDA would receive the unconstrained price
  - Load in the constrained LDA would be granted 4 GW of CTR credits worth $40 / MW-day

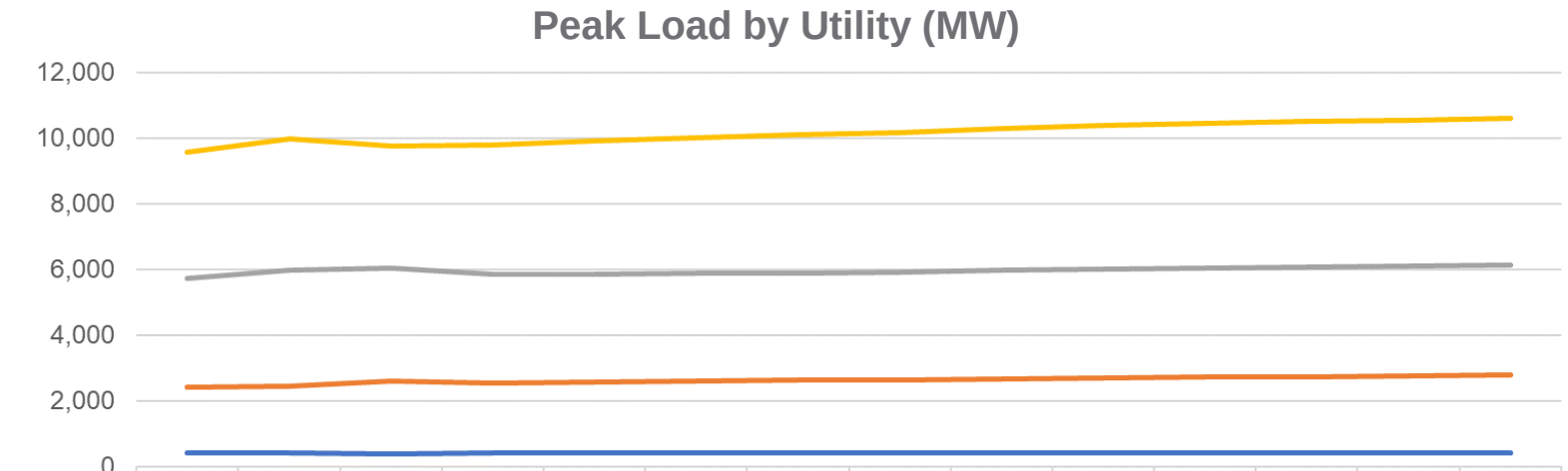


Source: Adapted from PJM material - https://www.pjm.com/-/media/training/nerc-certifications/markets-exam-materials/rpm/rpm-101-overview-of-reliability-pricing-model.ashx?la=en

FRR Model: Reflected Market Dynamics

Load Growth in FRR Scenarios

- To account for the fact that the first year of the FRR election in New Jersey *might* be the 2024/25 delivery period, CRA adjusted capacity volumes to reflect load growth in the intervening time after 2021/22.
- CRA has not attempted to reflect how changing demand would shift the VRR and therefore pricing outcomes; only ultimate volumes procured are considered.
- PJM forecasted peak load growth in the NJ LDAs is very limited, with CAGRs ranging 0.45-0.82%.
- As we show in a sensitivity analysis (presented later), assumptions about the study year from a load growth perspective are not meaningful drivers of results and do not alter conclusions.



	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
PSEG	9,567	9,978	9,753	9,792	9,911	10,029	10,095	10,177	10,298	10,382	10,455	10,522	10,557	10,597
JCPL	5,721	5,977	6,057	5,842	5,860	5,881	5,892	5,925	5,972	6,014	6,047	6,068	6,099	6,122
AECO	2,401	2,450	2,599	2,542	2,577	2,597	2,616	2,638	2,665	2,682	2,723	2,737	2,756	2,773
RECO	402	415	393	395	397	401	404	407	410	413	415	417	419	420

Sources: 2017-2019, EV data and CRA analysis – 2020 forward, PJM 2020 load forecast

FRR Modeling: Base Case Assumptions

The following represent the assumptions used in the "base case" for the NJ FRR modeling exercise. This is a list of default settings for key variables, but not an exhaustive list of all modeling assumptions.

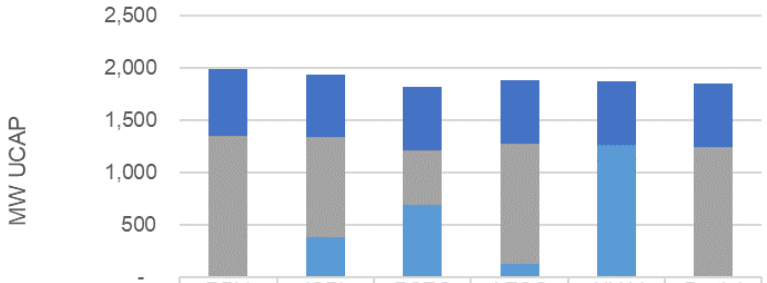
Variable – Status Quo Case	Base Case Value or Setting	Sensitivity of Results to Assumption
MOPR Effect	Salem and Hope Creek Clear in RPM New wind, new solar excluded from RPM	High
Payments to Excluded Clean Energy Resources	OSW receives negotiated OREC prices ($100/MWh) Solar and nuclear resources receive prevailing subsidies plus historical average EMAAC price ($175/MW-day)	High (limited modeled flexibility)

Variable – FRR Cases	Base Case Value or Setting	Sensitivity of Results to Assumption
Treatment of Nuclear	Both Salem and Hope Creek not in FRR Plan on basis different from other existing resources	High
Treatment of Solar and Wind	New solar resources procured under future NJ program design receive subsidy sufficient to make resources whole at expected LCOE of solar in NJ (NREL source) OSW receives negotiated OREC prices ($100/MWh)	Low
Premium Paid to Residual Capacity in Excess of EMAAC BRA Price	JCP&L, AECO, Partial FRR Cases – 5% PSEG FRR Case – 25% All NJ FRR Case – 45%	Moderate (most consequential for All NJ case) *See sensitivity analysis*
Partial FRR Excess Procurement (reflects imperfect match between clean resources and sub-metered FRR volumes)	5%	Low
UCAP Conversion Rules	Current rules (i.e., not ELCC)	Low

FRR Modeling: Base Case Results – Total Cost

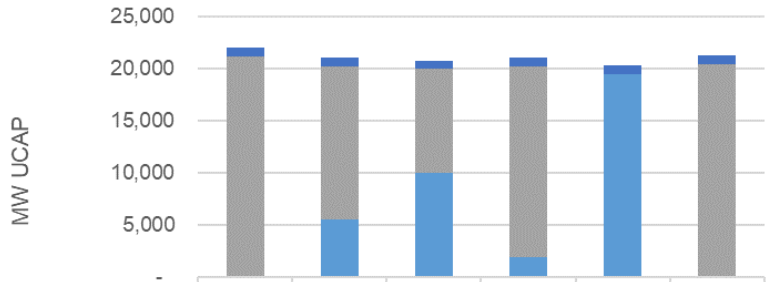
- Under base case assumptions, all FRR scenarios show a benefit to NJ ratepayers, though to a lesser degree than in a case where nuclear capacity is MOPR'ed (which, owing to rule interpretation, it will not be)
  - JCP&L FRR shows the least aggregate benefit, but we also expect will experience the among the least uncertainty driven by residual capacity procurement (what we view as a major driver of relative cost uncertainty).
  - The PSEG FRR and Partial FRR cases show the most benefit, though the PSEG FRR case (and the All NJ FRR case) has higher levels of uncertainty driven by residual capacity volumes.
- Total UCAP procured is highest in the RPM Status Quo case, which reflects both duplicative procurement (RPM plus NJ clean energy programs) and the fact that FRR requirements result in lower procurement volumes than the BRA produces.
- Split of capacity procurement costs by capacity type (RPM vs. Residual Capacity vs. CE Capacity) reflects variation in volumes across difference scenarios, with CE Capacity having the highest unit cost. RPM and Residual Capacity are similar on a per unit basis because Residual Capacity costs are assumed to be pegged to EMAAC prices.
- All savings are presented on an annual basis and meant to represent savings tied to resources expected in service in the 2024/25 delivery year. Based on the Energy Master Plan, we expect the volume of affected resources to increase, and also therefore expect calculated savings to also increase over time (further analysis on this provided later).

Total Cost by Scenario



	RPM Case (Base)	JCPL FRR (Base)	PSEG FRR (Base)	AECO FRR (Base)	All NJ FRR (Base)	Partial FRR (Base)
All NJ Total Cost	1,993	1,942	1,816	1,885	1,870	1,853
Clean Energy Pmts.	644	603	603	603	603	603
RPM Cost	1,349	954	526	1,156	-	1,247
Res. Capacity Cost	-	386	687	127	1,267	3

Total Capacity Procured

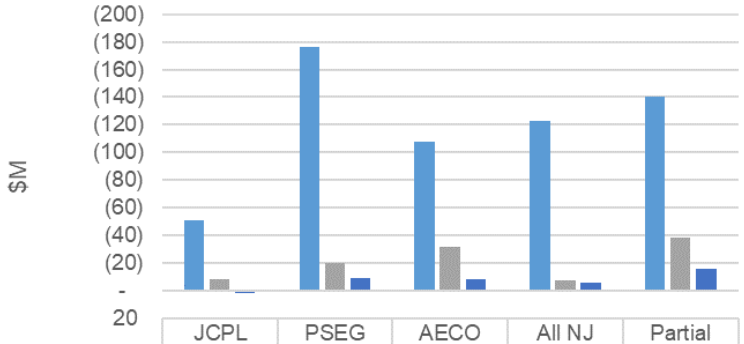


	RPM Case (Base)	JCPL FRR (Base)	PSEG FRR (Base)	AECO FRR (Base)	All NJ FRR (Base)	Partial FRR (Base)
Toal UCAP	22,057	21,057	20,815	21,061	20,345	20,815
Clean Energy UCAP	832	832	832	832	832	832
RPM Volume	21,225	14,640	9,961	18,293	-	20,404
Res. Capacity Volume	-	5,585	10,022	1,936	19,513	42

FRR Modeling: Base Case Results – Cost Savings

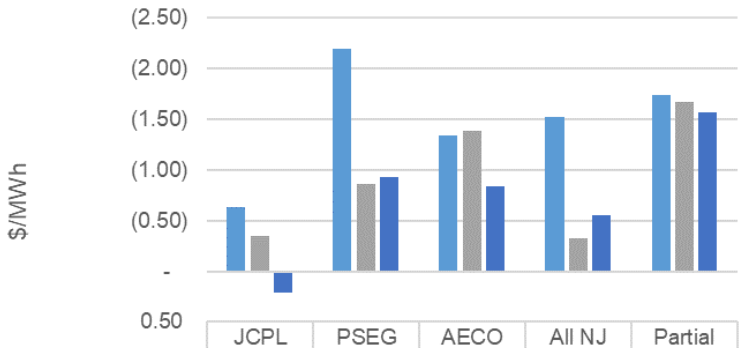
- Under base case assumptions, savings range from approximately $50-175M
  - Aggregate savings in the JCP&L case are lowest because this case 1) does not all allow NJ ratepayers to avoid paying the PSEG price premium experienced in RPM and 2) also has relatively high quantities of residual capacity procured at a premium to RPM prices. Both of these are major drivers of aggregate benefit from an FRR election.
  - AECO (and RECO) customers experience increased costs in the JCP&L FRR case as they do not benefit from reduced procurement volumes because they are not the FRR entity and the capacity price they experience rises (as assessed by the IMM in its analysis).
- Under base case assumptions, NJ ratepayers generally benefit as much or to a greater degree than JCP&L ratepayers:
  - JCP&L customers benefit less on a $/MWh basis owing to having a lower load factor than other NJ customers, on average, and therefore fewer MWh across which capacity costs may be allocated.
  - JCP&L customers benefit is lesser on a percentage basis in the PSEG FRR and All NJ cases owing to the fact that more significant benefits accrue particularly to PSEG customers in that case (no "break out" RPM price).
- ***Generally, major drivers of cost savings are:***
  - ***Avoiding duplicative capacity procurement, and ensuring that all resources are accounted for in overall PJM capacity procurement***
  - ***Avoiding PSEG capacity price premium experienced in RPM***
  - ***Limiting quantities of residual capacity procured at a premium***

Total Savings



	JCPL FRR (Base)	PSEG FRR (Base)	AECO FRR (Base)	All NJ FRR (Base)	Partial FRR (Base)
All NJ Cost Change	(51)	(176)	(108)	(123)	(140)
JCPL Cost Change	(8)	(20)	(32)	(7)	(38)
AECO Cost Change	2	(9)	(9)	(6)	(16)

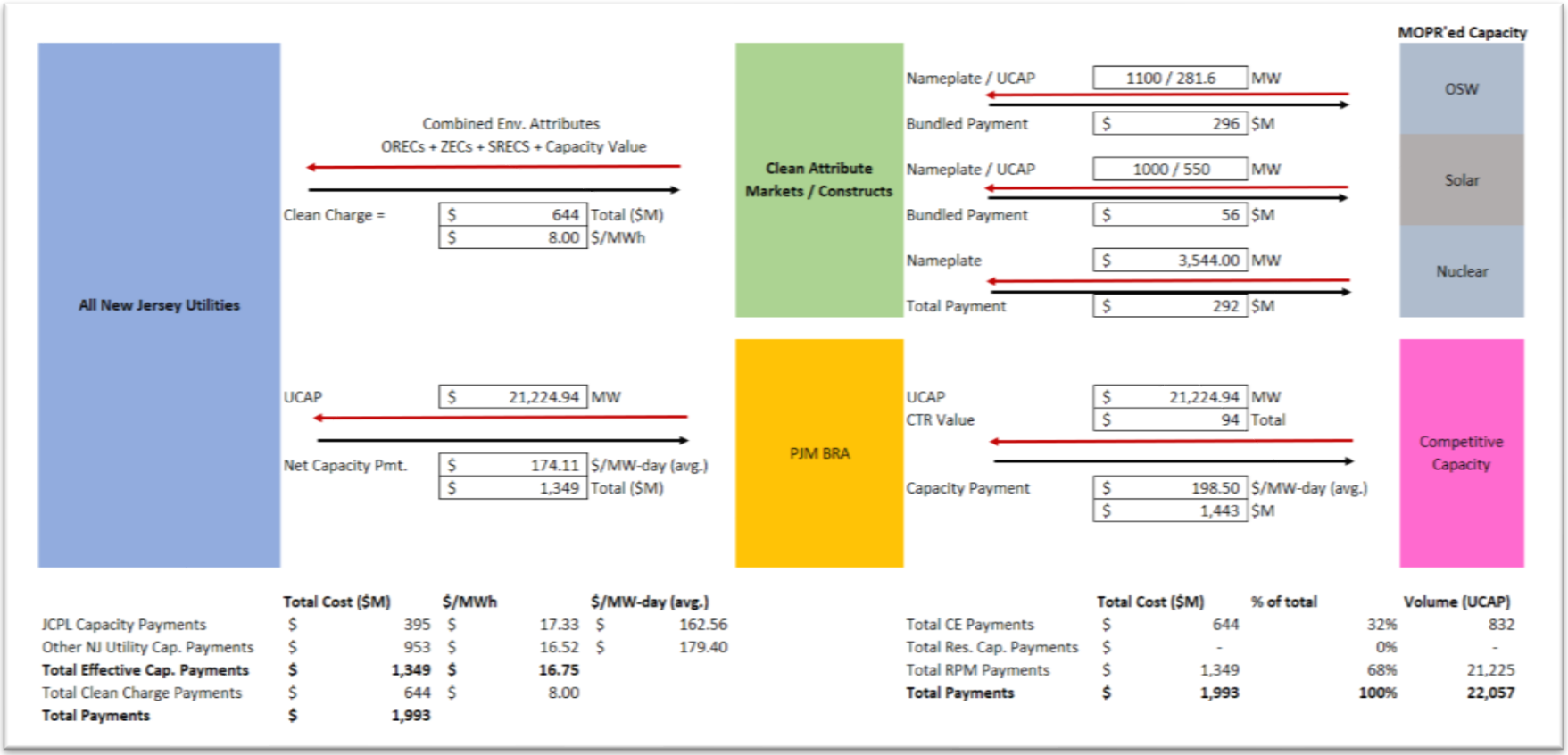
Unit Savings



	JCPL FRR (Base)	PSEG FRR (Base)	AECO FRR (Base)	All NJ FRR (Base)	Partial FRR (Base)
All NJ Unit Cost Change	(0.63)	(2.19)	(1.34)	(1.52)	(1.74)
JCPL Unit Cost Change	(0.35)	(0.86)	(1.39)	(0.32)	(1.67)
AECO Unit Cost Change	0.21	(0.93)	(0.84)	(0.55)	(1.57)

FRR Modeling: BRA Only Case (Reference / Status Quo)

In the reference case, there is no election of FRR Alternatives by any NJ LDA. All state preferred resources receive capacity payments “as needed” to make them whole for their inability to receive capacity revenue from RPM. Clean Energy payments, capacity payments, and total payments are all highest in this case.

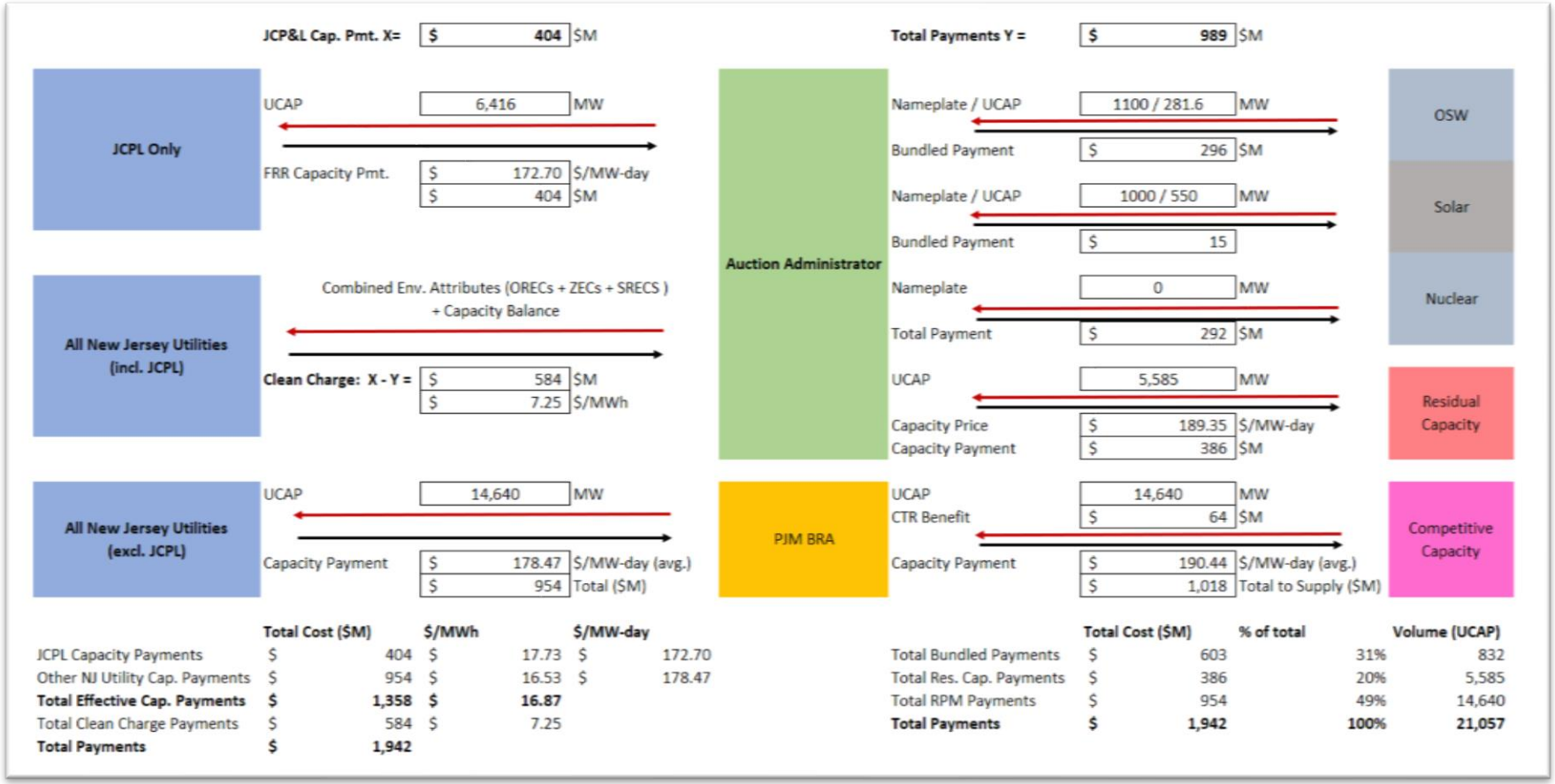


	Total Cost ($M)	$/MWh	$/MW-day (avg.)
JCPL Capacity Payments	$ 395	$ 17.33	$ 162.56
Other NJ Utility Cap. Payments	$ 953	$ 16.52	$ 179.40
Total Effective Cap. Payments	**$ 1,349**	**$ 16.75**	
Total Clean Charge Payments	$ 644	$ 8.00	
Total Payments	**$ 1,993**		

	Total Cost ($M)	% of total	Volume (UCAP)
Total CE Payments	$ 644	32%	832
Total Res. Cap. Payments	$ -	0%	-
Total RPM Payments	$ 1,349	68%	21,225
Total Payments	**$ 1,993**	**100%**	**22,057**

FRR Modeling: JCP&L FRR Case

In the JCP&L FRR case, it is assumed that of the NJ utilities only JCP&L elects the FRR alternative. JCP&L customers are responsible for a capacity payment that is linked to the EMAAC price, and all other costs are split pro rata among all NJ load.

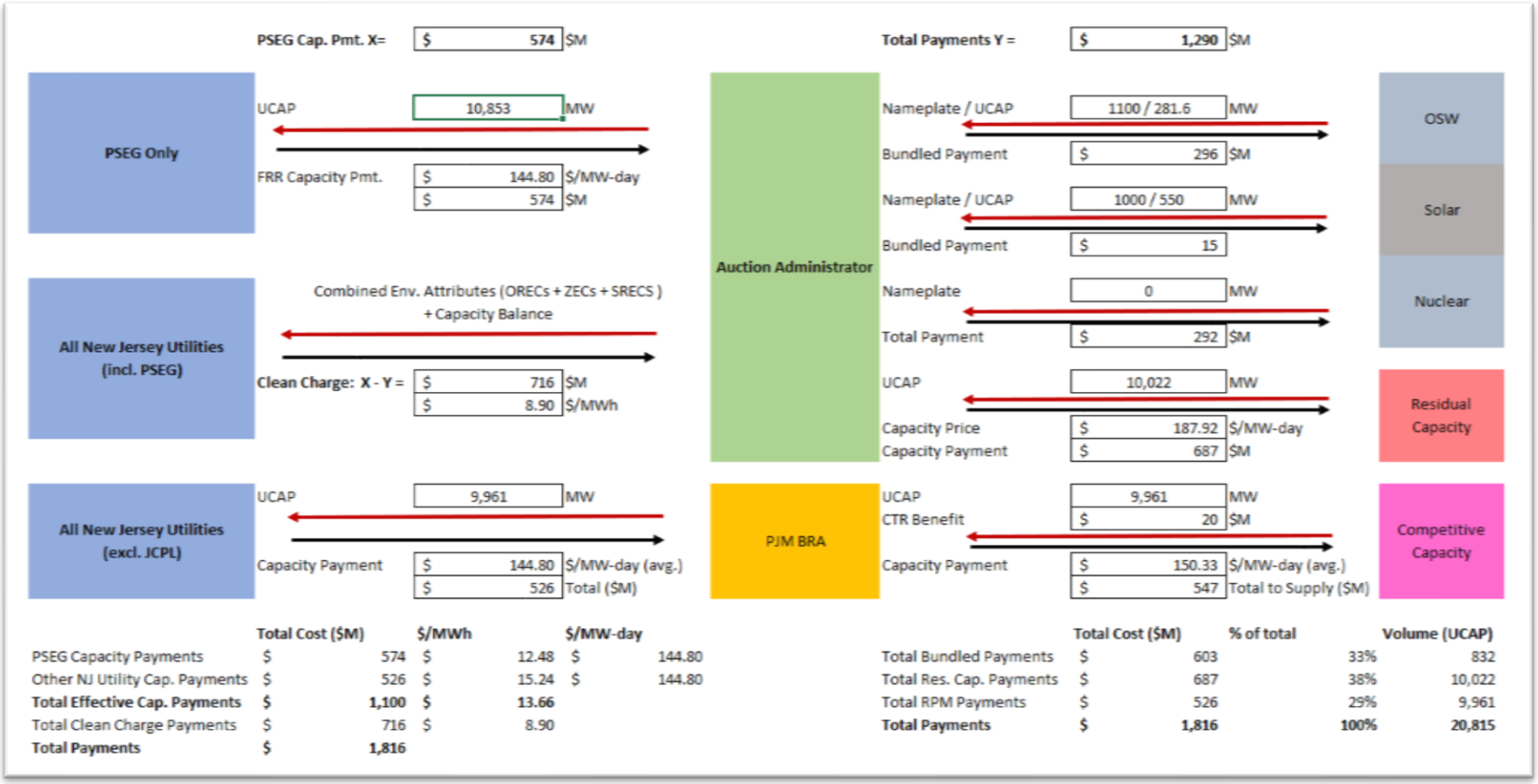


	Total Cost ($M)	$/MWh	$/MW-day
JCPL Capacity Payments	$ 404	$ 17.73	$ 172.70
Other NJ Utility Cap. Payments	$ 954	$ 16.53	$ 178.47
Total Effective Cap. Payments	**$ 1,358**	**$ 16.87**	
Total Clean Charge Payments	$ 584	$ 7.25	
Total Payments	**$ 1,942**		

	Total Cost ($M)	% of total	Volume (UCAP)
Total Bundled Payments	$ 603	31%	832
Total Res. Cap. Payments	$ 386	20%	5,585
Total RPM Payments	$ 954	49%	14,640
Total Payments	**$ 1,942**	**100%**	**21,057**

FRR Modeling: PSEG FRR Case

In the PSEG FRR case, it is assumed that of the NJ utilities only PSEG elects the FRR alternative. PSEG customers are responsible for a capacity payment that is linked to the EMAAC price, and all other costs are split pro rata among all NJ load. Owing to the larger difference between the quantity of state preferred capacity and the FRR procurement obligation for PSEG, residual capacity payments are larger in this case than in the JCP&L FRR case.

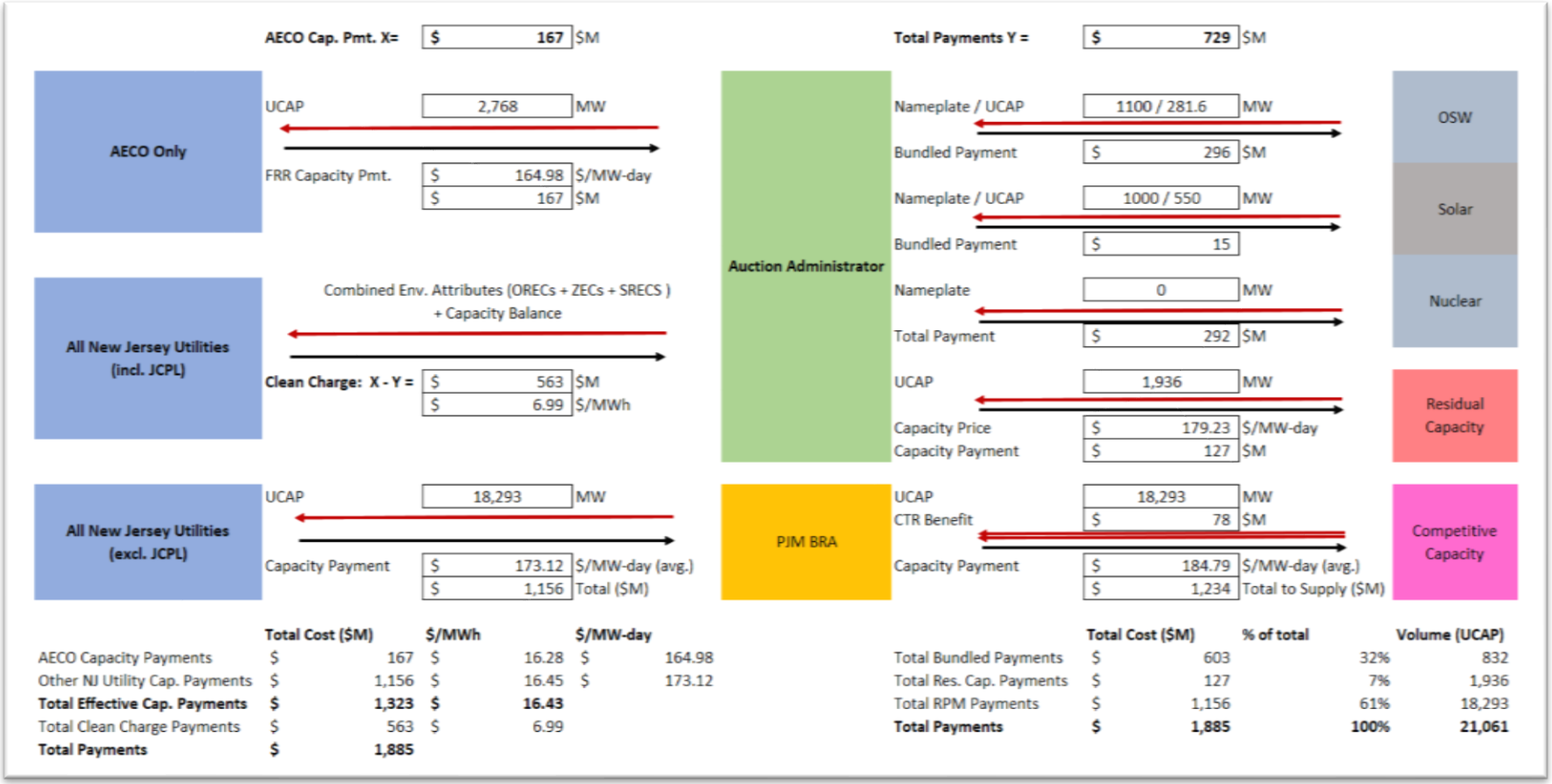


	Total Cost ($M)	$/MWh	$/MW-day
PSEG Capacity Payments	$ 574	$ 12.48	$ 144.80
Other NJ Utility Cap. Payments	$ 526	$ 15.24	$ 144.80
Total Effective Cap. Payments	**$ 1,100**	**$ 13.66**	
Total Clean Charge Payments	$ 716	$ 8.90	
Total Payments	**$ 1,816**		

	Total Cost ($M)	% of total	Volume (UCAP)
Total Bundled Payments	$ 603	33%	832
Total Res. Cap. Payments	$ 687	38%	10,022
Total RPM Payments	$ 526	29%	9,961
Total Payments	**$ 1,816**	**100%**	**20,815**

FRR Modeling: AECO FRR Case

In the AECO FRR case, it is assumed that of the NJ utilities only ACE elects the FRR alternative. AECO customers are responsible for a capacity payment that is linked to the EMAAC price, and all other costs are split pro rata among all NJ load. For this case, no IMM FRR scenarios were available to inform price and quantity assumptions. We thus used a reasoned blend of other cases to inform expected BRA price and quantity results.

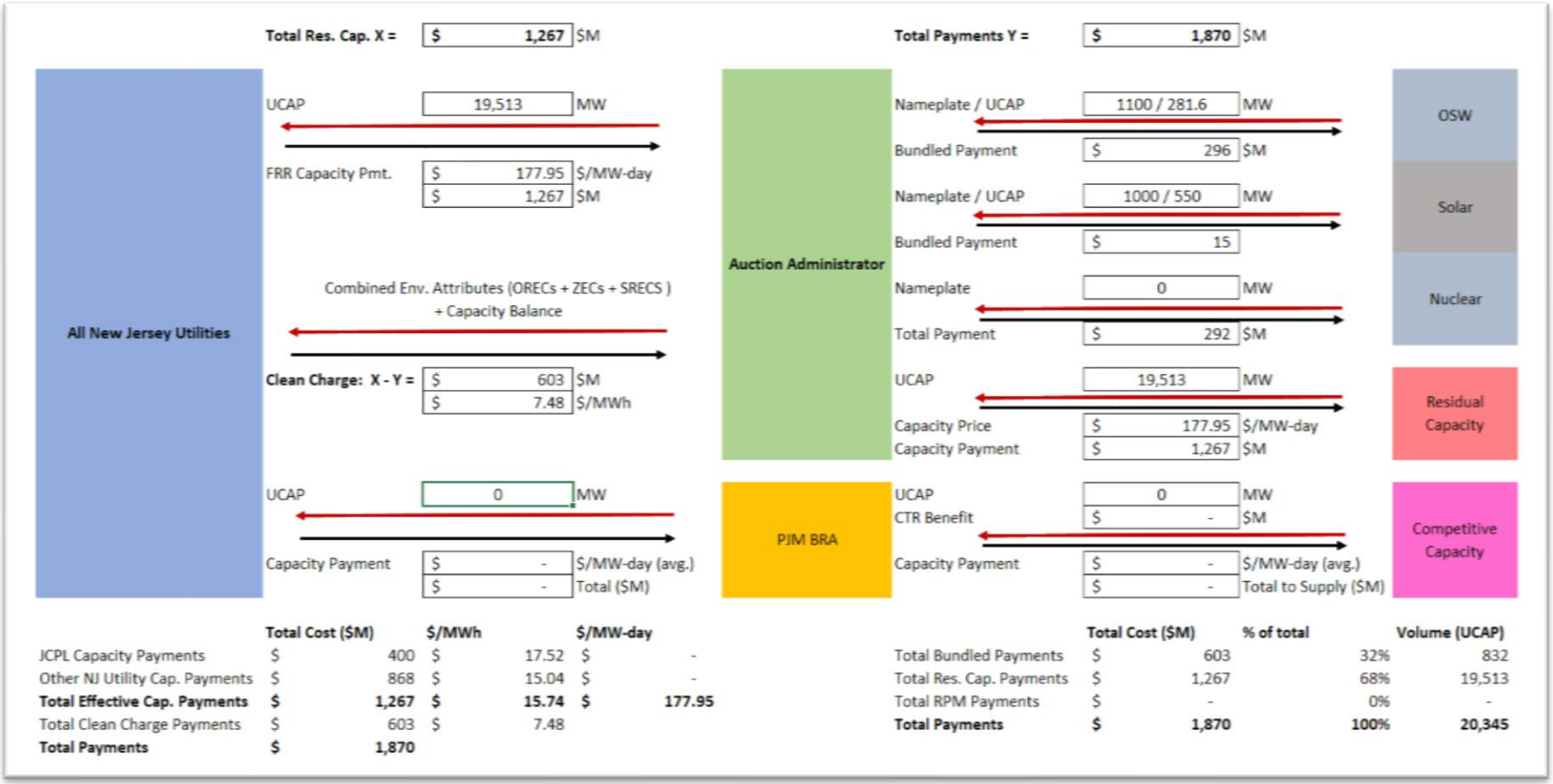


	Total Cost ($M)	$/MWh	$/MW-day
AECO Capacity Payments	$ 167	$ 16.28	$ 164.98
Other NJ Utility Cap. Payments	$ 1,156	$ 16.45	$ 173.12
Total Effective Cap. Payments	**$ 1,323**	**$ 16.43**	
Total Clean Charge Payments	$ 563	$ 6.99	
Total Payments	**$ 1,885**		

	Total Cost ($M)	% of total	Volume (UCAP)
Total Bundled Payments	$ 603	32%	832
Total Res. Cap. Payments	$ 127	7%	1,936
Total RPM Payments	$ 1,156	61%	18,293
Total Payments	**$ 1,885**	**100%**	**21,061**

FRR Modeling: All NJ FRR Case

In the All NJ FRR case, it is assumed that all NJ utilities elect the FRR alternative. All NJ customers are responsible for a capacity payment that is assumed to be the EMAAC price plus a premium to reflect what it would take to procure sufficient capacity, and all other costs are also split pro rata among all NJ load. This case has the largest quantity of residual capacity payments and no BRA payments.

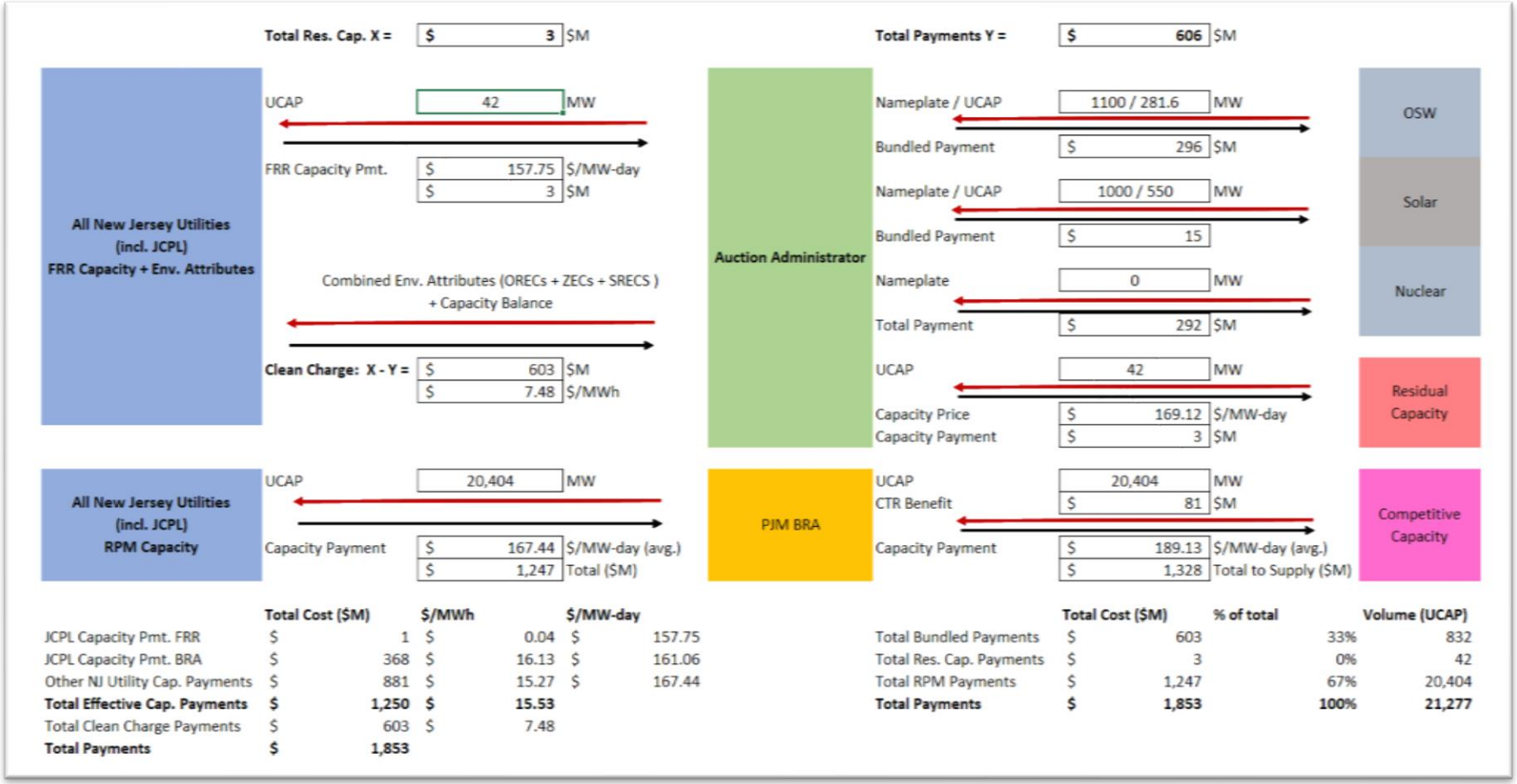


	Total Cost ($M)	$/MWh	$/MW-day
JCPL Capacity Payments	$ 400	$ 17.52	$ -
Other NJ Utility Cap. Payments	$ 868	$ 15.04	$ -
Total Effective Cap. Payments	**$ 1,267**	**$ 15.74**	**$ 177.95**
Total Clean Charge Payments	$ 603	$ 7.48	
Total Payments	**$ 1,870**		

	Total Cost ($M)	% of total	Volume (UCAP)
Total Bundled Payments	$ 603	32%	832
Total Res. Cap. Payments	$ 1,267	68%	19,513
Total RPM Payments	$ -	0%	-
Total Payments	**$ 1,870**	**100%**	**20,345**

FRR Modeling: Pro Rata ("Partial") FRR Case

In the Partial FRR case, it is assumed that a fraction of all NJ utilities elect the FRR alternative, as enabled by the PJM tariff, in a total quantity sufficient to support procurement of all of the state preferred resources. A small additional amount of residual capacity procurement is assumed to reflect an inability to precisely match sub-metered load to subsidized UCAP. The remainder of capacity in each LDA is procured through RPM. This case has the smallest quantity of residual capacity payments.



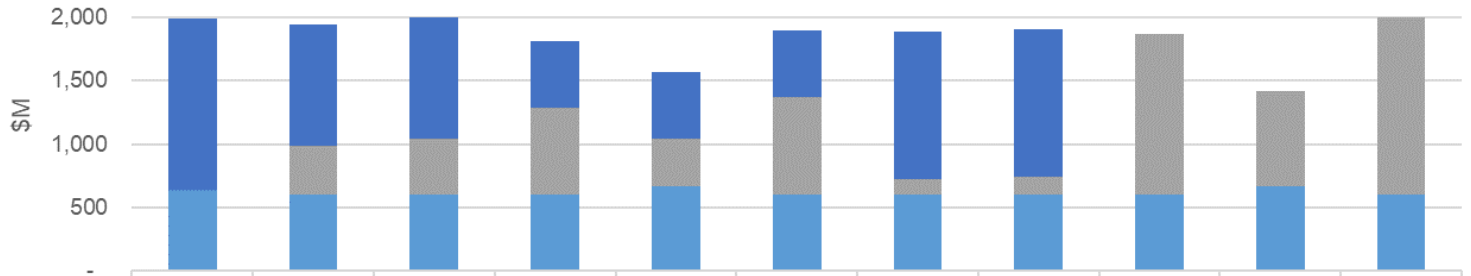
	Total Cost ($M)	$/MWh	$/MW-day
JCPL Capacity Pmt. FRR	$ 1	$ 0.04	$ 157.75
JCPL Capacity Pmt. BRA	$ 368	$ 16.13	$ 161.06
Other NJ Utility Cap. Payments	$ 881	$ 15.27	$ 167.44
Total Effective Cap. Payments	**$ 1,250**	**$ 15.53**	
Total Clean Charge Payments	$ 603	$ 7.48	
Total Payments	**$ 1,853**		

	Total Cost ($M)	% of total	Volume (UCAP)
Total Bundled Payments	$ 603	33%	832
Total Res. Cap. Payments	$ 3	0%	42
Total RPM Payments	$ 1,247	67%	20,404
Total Payments	**$ 1,853**	**100%**	**21,277**

FRR Modeling: FRR Premium for Residual Capacity

- Under varying assumptions regarding the cost of procuring residual capacity, most cases still show aggregate savings to NJ ratepayers. Only in the most extreme modeled scenarios do FRR costs show a limited increase relative to the RPM Case
- The assumption about the price to be paid to residual capacity can affect results and conclusions by impacting total cost of residual capacity:
  - This effect is more pronounced the larger the quantity of expected residual capacity to be procured (e.g., in the PSEG FRR and All NJ FRR cases).
  - In the JCP&L FRR, AECO FRR, and Partial FRR cases, this assumption has a more limited effect and is therefore a less significant driver of results.
- As will be discussed in later sections, the more residual capacity that needs to be procured, and the more constraints that need to be respected, the harder it may be to procure residual capacity at low costs (i.e., similar to EMAAC price).
- These results represent both a major opportunity and a major uncertainty associated with any FRR approach.
- Additional Notes:
  - Partial FRR case not shown because residual capacity volumes are so small in that scenario
  - Base Case Premiums (all over estimated EMAAC price): JCP&L / AECO = 5%, PSEG = 25%, All NJ = 40%

Total FRR Scenario Costs Varying Assumed Residual Capacity Premium

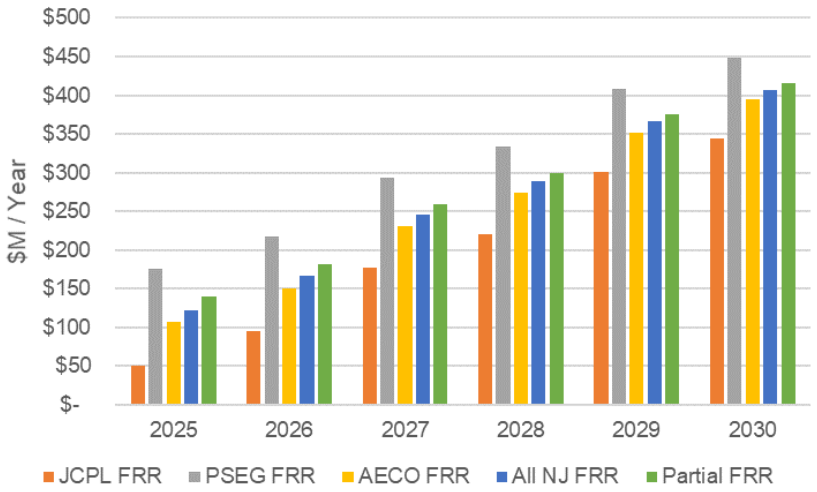


	RPM Case (Base)	JCPL FRR (Base)	JCPL FRR (20% premium)	PSEG FRR (Base)	PSEG FRR (5% premium)	PSEG FRR (40% premium)	AECO FRR (Base)	AECO FRR (20% premium)	All NJ FRR (Base)	All NJ FRR (5% premium)	All NJ FRR (60% premium)
All NJ Total Cost	1,993	1,942	1,997	1,816	1,573	1,899	1,885	1,903	1,870	1,424	2,001
RPM Cost	1,349	954	954	526	526	526	1,156	1,156	-	-	-
Res. Capacity Cost	-	386	441	687	375	770	127	145	1,267	753	1,399
Clean Energy Pmts.	644	603	603	603	671	603	603	603	603	671	603

FRR Modeling: Quantity of NJ Clean Energy Resources

- All other analysis presented in this report focuses on results for the first delivery year (2024/25) in which NJ offshore wind will be online and excluded from selling capacity into RPM because of the revised MOPR rules.
- Here, we present a sensitivity analysis of how the results would change if quantities of subsidized (and MOPR'ed) wind and solar were increased as they are expected to under the NJ Energy Master Plan.
- As quantities of MOPR'ed clean energy capacity increase over time, the expected cost savings from electing the FRR increase across all modeled scenarios. This reflects the growth in duplicative capacity procurement as subsidized volumes increase (and associated effects). Consistent with this trend, conclusions about the benefits of FRR election become less ambiguous when looking across a longer time horizon.
- This results should be seen as indicative of the trend that would be expected. However, there are a range of market dynamics that could manifest over time that we have not attempted to represent in our single-year analysis approach.
- In each case, PSEG stands out as having the largest expected level of savings. This is largely driven by the fact that PSEG experienced a large price breakout (~$40/MW-day) in the reference BRA (21/22). Could this analysis be repeated with a reference year in which the PSEG LDA did not break out, we would expect PSEG results to be more in line with other results.

Savings Under Increasing Quantities of Subsidized Wind and Solar



New Subsidized Capacity Build Schedule

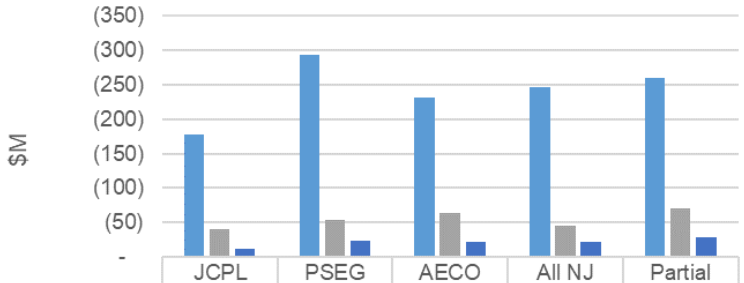
Year	Added OSW ICAP	Installed OSW ICAP	Added Solar ICAP	Installed Solar ICAP
2025	1,100	1,100	1,000	1,000
2026	0	1,100	400	1,400
2027	1,200	2,300	400	1,800
2028	0	2,300	400	2,200
2029	1,200	3,500	400	2,600
2030	0	3,500	400	3,000

FRR Modeling: Quantity of NJ Clean Energy Resources

Focus on Relative Impacts

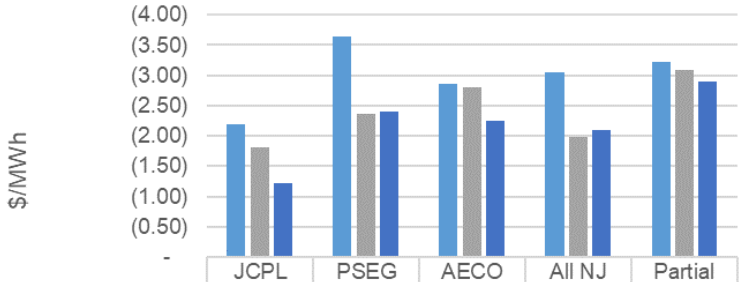
As NJ Clean Energy volumes grow, benefits increase in aggregate and the distribution of benefits becomes more consistent between NJ ratepayers as a whole and JCP&L ratepayers (as compared to base case 2025).

Total Savings (2027 Volumes)



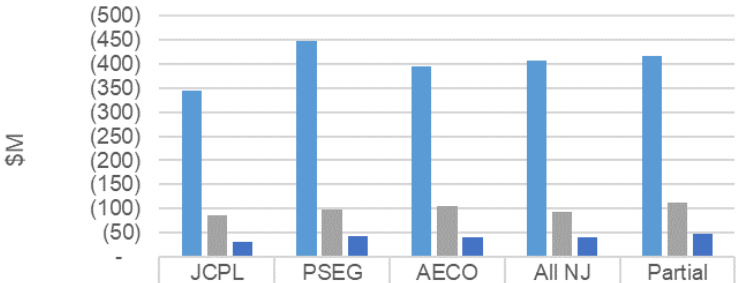
	JCPL FRR	PSEG FRR	AECO FRR	All NJ FRR	Partial FRR
All NJ Cost Change	(177)	(294)	(231)	(246)	(259)
JCPL Cost Change	(41)	(54)	(64)	(45)	(70)
AECO Cost Change	(13)	(25)	(23)	(22)	(30)

Per Unit Savings (2027 Volumes)



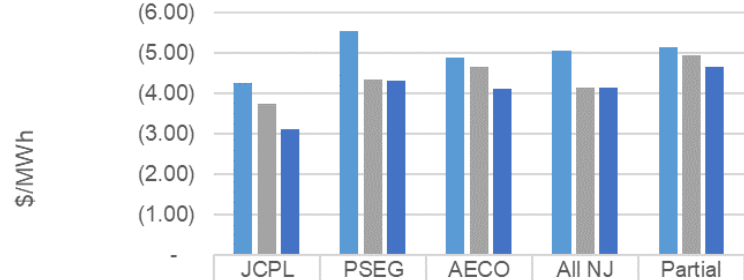
	JCPL FRR	PSEG FRR	AECO FRR	All NJ FRR	Partial FRR
All NJ Unit Cost Change	(2.20)	(3.65)	(2.87)	(3.06)	(3.22)
JCPL Unit Cost Change	(1.81)	(2.37)	(2.80)	(1.98)	(3.09)
AECO Unit Cost Change	(1.22)	(2.39)	(2.26)	(2.11)	(2.90)

Total Savings (2030 Volumes)



	JCPL FRR	PSEG FRR	AECO FRR	All NJ FRR	Partial FRR
All NJ Cost Change	(344)	(448)	(394)	(407)	(415)
JCPL Cost Change	(86)	(99)	(107)	(95)	(113)
AECO Cost Change	(32)	(44)	(42)	(42)	(48)

Per Unit Savings (2030 Volumes)



	JCPL FRR	PSEG FRR	AECO FRR	All NJ FRR	Partial FRR
All NJ Unit Cost Change	(4.27)	(5.56)	(4.90)	(5.06)	(5.16)
JCPL Unit Cost Change	(3.75)	(4.35)	(4.67)	(4.14)	(4.96)
AECO Unit Cost Change	(3.12)	(4.33)	(4.13)	(4.14)	(4.67)

FRR Modeling: Additional Sensitivities

CRA performed a number of additional modeling sensitivities to test the impact of certain assumptions. None of these sensitivity tests shifted the relative expected savings of the various scenarios, with the exception of the one case under the high renewables ELCC case.

- **Increase estimated all-in cost of utility scale solar**: Owing to uncertainties in technology cost change and development costs in New Jersey, we test the impact of increasing LCOE from $36/MWh in the base case to $44/MWh. This somewhat decreases savings in the FRR cases as the assumed bundled procurement cost of those resources would rise.
- **Remove assumed load growth between 2021/22 and 2024/25**: As described in our methodology, we accounted for capacity volume growth consistent with PJM forecasts (without associated price impacts). Eliminating this volume growth results in a small reduction (or increase) in savings owing to the smaller number of total capacity units in the analysis and varying volumes of residual capacity.
- **Employ alternative UCAP adjustors for renewable generators**: PJM is considering a change to an ELCC methodology for UCAP adjustments for renewables. We tested the impact of applying two preliminary sets of PJM results. The more significant the aggregate reduction in capacity credit granted to renewables, the larger the magnitude of the change in the FRR case – this follows largely from reduced cost in the RPM case from less duplicative procurement as well as increased costs in the FRR cases from the need to purchase more nameplate renewable capacity to fulfill obligations.

$M ($M change from base)	JCP&L FRR	PSEG FRR	AECO FRR	All NJ FRR	Partial FRR
Base Savings	51	159	108	123	140
Utility Scale Solar LCOE = $44/MWh	34 (-17)	160 (0)	91 (-17)	106 (-17)	123 (-17)
Remove Load Growth Assumption	50 (0)	171 (+12)	107 -(1)	118 (-5)	138 (-2)
Early PJM ELCC Results Low Case (2)	44 (-6)	171 (+11)	102 (-6)	117 (-6)	135 (-6)
Early PJM ELCC Results High Case (5)	-1 (-51)	129 (-31)	58 (-50)	73 (-50)	92 (-48)

We conclude that the key uncertainties revolve the cost of residual capacity. The expected magnitude of FRR savings are also expected to increase considerably as subsidized clean energy volumes grow. Other factors are less impactful. Under the scenarios analyzed, there are only a few case that would lead to total cost increase relative to the RPM Case. Concerns about total cost increases would only be expected to arise under situations that combine pessimistic sensitivities.

FRR Modeling: Transmission and Price Uncertainty

- Relevant capacity constraints - capacity emergency transfer limits (CETL) – are developed annually by PJM to reflect expected transmission constraints during peak periods. Key drivers include changes in transmission topology, shifts in load location and timing, generator additions or retirements, and changes in forced outage expectations.
- CRA's modeling does not attempt to reflect changes in CETLs that may be affected by planned or future infrastructure development.
- We observe that recent network upgrades in and around the EMAAC and PSEG constraints have done little to affect total CETL levels year-over-year.
- Historically, there has been a weak correlation between the magnitude of price separation and changes in CETL
  - A decline in the PSEG CETL may have been a contributing factor to the breakout of the LDA in 2021/22.
  - For the 2022/23 auction, the CETL will increase, and we also expect peak load forecasts to be revised downward due to COVID, reducing the likelihood that PSEG will break out again as it did in the 2021/22 BRA.
- Note that as CETLs increase, the total impact of higher prices on load decreases, as higher CETLs are associated with larger volumes of CTR credits and fewer MW that need to be paid higher "constrained" price.
- While we do not reflect CETL dynamics in our modeling, we expect that this should not significantly impact our ultimate conclusions, as this analysis focuses on relative price impacts and not absolute pricing outcomes

Price ($/MWh)	2018/19	2019/20	2020/21	2021/22	2022/23
RTO	164.77	100.00	76.53	140.00	-
MAAC	164.77	100.00	86.04	140.00	-
EMAAC	225.42	119.77	187.87	165.73	-
PSEG / PSEG-N	225.42	119.77	187.87	204.29	-
CETL (MW)					
MAAC	7,883	7,385	4,218	4,019	2,252
EMAAC	8,375	8,856	8,800	9,150	9,752
PSEG	7,926	7,856	8,001	6,902	7,445
PSEG-N	3,761	3,827	4,264	3,180	3,777

Reference: https://pjm.com/-/media/committees-groups/committees/pc/20171103-special/20171103-ceto-cetl-education-presentation.ashx

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Procurement Considerations: Summary of Findings

This section presents analysis of issues associated with procurement design under an FRR Alternative election under any of the assessed scenarios. It complements the quantitative assessment of total customer costs provided in the prior section. We make the following high level observations:

- **Clean Energy Procurement**: Contracting with OSW and utility-scale resources may be done on a competitive, bundled basis with long-term contracts. Contracting with nuclear resources, if done on a nuclear-specific basis, likely lends itself to cost-based remuneration.
- **Residual Capacity Procurement**: Resources participating in the residual capacity procurement to be included in an FRR Plan will face a novel set of incentives. We suggest an auction design that is consistent with these incentives and will result in a cost effective outcome.
- **Market Power**: As with RPM, market power issues are likely to be a concern with residual capacity procurement, particularly if the constrained PSEG LDA is part of the FRR election. We present mitigation options should they be necessary.
- **Risk Management:** For resources included in the FRR Plan, the FRR Entity will take on performance risk on their behalf. To ensure equitable exposure to such risk on the part of customers of the FRR Entity, we suggest several alternatives to, via contracts and regulatory arrangements, reallocate those risks to suppliers and/or all NJ ratepayers.
- **Timing Considerations**: There is a different MOPR-related risk profile for NJ ratepayers in the near term (pre-2024/25 delivery period) and long term (2024/25 and after). This may inform how quickly New Jersey moves to implement an FRR, if it chooses to do so.
- **Reliability Impact**: Though mandated resource adequacy levels will be maintained, election of an FRR will technically lead to lower levels of reliability, all else equal, largely because inaction will result in over-procurement of capacity.
- **Administrative Cost**: While relatively small on the scale of costs being addressed throughout this report, the FRR Entities will incur administrative cost associated with implementing the FRR Alternative. These cost should be recoverable in a manner that is not unduly burdensome on a subset of NJ customers.

FRR Procurement: Offshore Wind and Utility-Scale Solar

- Key to the underlying purpose of implementing the FRR Alternative is including the NJ subsidized resources – those necessary to achieve the Energy Master Plan – in the FRR Plan. We generally support the procurement approach put forth by PSEG, Exelon, and Northbridge for utility-scale solar and offshore wind resources*:
  - **Product**: bundled product of energy, ancillary services, capacity, and environmental attributes. We note that procuring a bundled product should increase economic and administrative efficiency, as opposed to attempting to procure various products in sequenced tenders.
  - **Compensation**: resources paid as-bid all-in prices for the contract term, escalated for inflation and net of (actual or forecast) energy, ancillary service, and environmental credit revenues. This increases price certainty for both generators and load, and should reduce development risk and in doing so potentially reduce financing costs and ultimately cost to consumers.
  - **Term**: long-term contracts sufficient to provide certainty to developers (e.g.,15+ years). We expect that providing termed contracts will also reduce development risk and ultimately cost to customers.
  - **Volume**: procurement targets would be consistent with targets in Energy Master Plan. We suggest some flexibility be built in to over-procure capacity owing to the lumpiness and economies of scale of generation development, particularly for OSW resources.
  - **Cost Controls**: procurement for each resource price would be subject to not-to-exceed price based on recent procurements in an appropriate reference group.
- The above appears to be generally consistent with procurement approaches taken with OSW in New Jersey to date, and what would be expected for future such resources. These protocols could be extended to future state procurements of utility-scale solar. This leads us to the following observations:
  - As an initial matter, even if it was possible, we do not see the need to revisit the one completed OSW procurement.
  - For renewable resources to satisfy the Energy Master Plan, there do not appear to be entirely new procurement processes. Rather, existing processes could be extended to future volumes of clean energy.
  - Resources procured through state-sponsored procurements could then be automatically included in the FRR Plan.
  - This would leave only nuclear and residual capacity to be procured specifically to fulfill the FRR Obligation.
- Little is being proposed here that is novel. The only significant suggestion is to extend the style and structure of OSW procurement to utility-scale solar. From an uncertainty and risk standpoint, we view this extension as adding little of either. Competitive procurements for utility-scale solar in the US are well understood and have produced impressive results in terms of both realized costs and improvement over time.

* **Note**: Our conclusions here are limited to procurement of and compensation for energy, ancillary services, and capacity products. To the extent that procurements include transmission interconnection infrastructure and necessary system upgrades and the rate treatment thereof, we take no position.

FRR Procurement: Nuclear Capacity

- For Salem and Hope Creek to be included in the FRR Plan in any scenario on a basis different from other existing capacity resources, a mechanism would need to be established to provide compensation for provided capacity.
- If it is a specific state objective to have these two nuclear facilities necessarily included in the FRR Plan, there is no way to run a competitive procurement specific to nuclear capacity given that supply would exactly match demand and there is no competition from new entrants.
- Instead, we present the following three alternative approaches:
  - Procure nuclear with other Tier 2 resources, as suggested by PSEG and Exelon, while resources continue to receive ZEC payments. This raises concerns about market power – depending on procurement design – and leaves the possibility that the facilities could go unselected in the FRR Plan, potentially leaving them without sufficient revenue to continue economic operations.
  - Maintain the existing ZEC subsidy and provide capacity compensation for the NJ nuclear units based on a historical benchmark capacity payment (or similar). This risks considerable over-payment by NJ ratepayers and provides no competitive pressure.
  - Negotiate a bundled cost-based compensation for the NJ nuclear units, similar to the structure of the OREC program, with ongoing regulatory oversight. This provides no competitive pressure, but provides other protections for NJ customers.
- The latter two approaches would need to have a periodic reassessment by the state as to whether nuclear continues to be a cost-effective part of achieving NJ energy policy goals, as well as payment offramps if the answer is negative.

Plant Name	ICAP (UCAP)	Ownership	Technology	Interconnected Utility*	Online Date
Salem	2,372 MW (2,348 MW)	PSEG 47% Exelon 53%	Pressurized Water Reactor (2 Units)	PSEG	June 1977 Oct 1981
Hope Creek	1,190 MW (1,160 MW)	PSEG 100%	Boiling Water Reactor (1 Unit)	PSEG	December 1986

* **Note**: Artificial Island, which is where Salem and Hope Creek reside, is internal to the EMAAC LDA and not the PSEG LDA (i.e., the generation is located outside of the PSEG capacity constraint). *Source*: May 20 PJM filing in BPU docket

FRR Procurement: Residual Capacity

- In fulfilling the FRR Obligation for the entity electing the FRR, any capacity not satisfied by NJ preferred resources (nuclear, OSW, utility-scale solar) will need to be procured from the broader PJM footprint – accounting for constraints – on a bilateral basis, though the structure that defines which entities receive contracts remains flexible.

- Procuring residual capacity for an FRR Plan, while still part of the broader PJM construct, creates unique challenges and incentives for the FRR Entity.

- The following slides present our assessment of the issues associated with the various NJ FRR scenarios, broken down into the following topic areas:

  - Description of incentives faced by generators considering participation in a tender to provide FRR capacity
  - Suggestion for a “straw man” procurement design to be run by the FRR procurement administrator that accounts for those incentives and maintains the benefits of competition, in part by linking prices to RPM outcomes
  - Market power analysis for potential FRR procurement processes under the various NJ FRR scenarios
  - Suggestions for mitigation options for market power in a residual capacity procurement for one or more NJ LDAs
  - Discussion of how transmission constraints (CETLs) in the NJ market areas may affect residual capacity procurement

- Given that resources in the FRR Plan may change from year to year, we do not see a need to procure residual capacity for multi-year terms. Doing so could be beneficial, but also raises concern about uneconomic lock-in and is not conceptually consistent with our suggested approach. Under different residual procurement structure, offering long-term contracts to residual supply could hold benefits of improved pricing terms in exchange for multi-year price certainty. However, this benefit could be outweighed by its drawbacks and would need to be considered carefully.

Residual Capacity: Incentives & Procurement Design

Conventional Capacity Market Offer Incentives

- Theory suggests that resources will submit capacity sell offers based on the opportunity cost of not taking on a capacity market obligation.
- In the status quo RPM environment, there were two primary considerations when developing such an offer: (1) avoidable going forward costs and (2) capacity performance opportunity costs.
- A "rational" offer would be based on the higher of these two opportunity cost considerations.

	Offer Basis	Practical Observation
Avoidable Going Forward Costs	Resources would be expected to offer such that they would be better off receiving a capacity payment, plus expected energy and ancillary revenue, than mothballing or retiring, which would allow avoidance of certain O&M costs.	For many resources, this calculus yields a low or zero offer price. Older resources and/or resources facing significant environmental compliance costs generally have the highest calculated net avoidable costs (and will ultimately set market prices).
Capacity Performance Opportunity Cost	Under the CP rules, resources would also be expected to consider the possibility of receiving (sizeable) bonus payments for full generation quantities during performance events should they not take on a capacity obligation. Offers should reflect a risk-adjusted, probability weighted expectation of capacity performance bonus payments for a non-committed resource.	CP events have been less frequent than expected since the program began.* Also, we expect that generator operators prefer the certainty of capacity revenues over the uncertainty of potentially large (or zero) CP bonus payments. Thus, the impact of CP implementation on capacity market offers and outcomes has been limited. (This consideration may depend on how CP risk is shared within the FRR Plan portfolio.)

* **Note**: with the proposed MOPR reforms and the resulting duplicative procurement, we expect that the market will be even longer on energy and capacity than it already is, which will in turn further reduce the expected frequency of CP events.

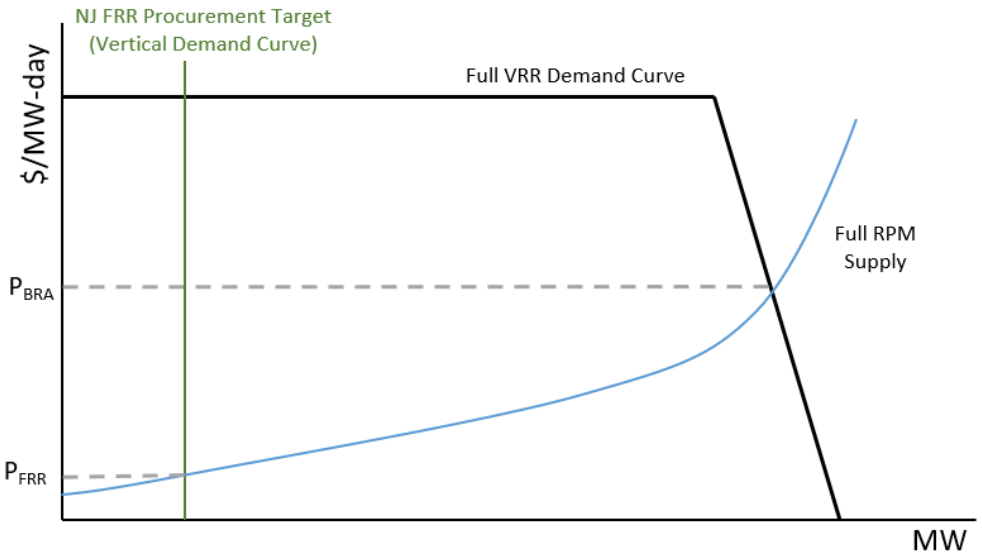
Residual Capacity: Incentives & Procurement Design

Inapplicability of Conventional Incentives in FRR Procurement

- In an FRR procurement, there are additional considerations associated with offering a sale of capacity:
  - If they sell into the FRR procurement, they forgo the opportunity to sell into the BRA at whatever price is produced by that auction.
  - The price in the BRA is expected to be higher that what the FRR procurement would produce should resources offer based on a conventional "rational" offer construct for RPM.

- Because the FRR procurement would represent only a limited fraction of total market demand for capacity, a supply curve of conventional offers would likely yield a dramatically lower price (P_{FRR} below, rather than P_{BRA}).

- This suggests a *third* opportunity cost-type consideration for resources offering to sell FRR capacity.



* **Note**: A similar dynamic is observed in the NYISO ICAP capacity market, wherein there are three auctions (strip, monthly, spot) and the full demand curve is only employed in the spot market. It is our understanding that, for this reason, in the ICAP construct the majority of non-bilateral market transactions occur in the spot market.

Residual Capacity: Incentives & Procurement Design

Additional Capacity Offer Incentives in FRR Procurement

- Accounting for the realities of selling capacity into an FRR plan, resources should also be expected to account for the opportunity cost of selling into the BRA, which would be expected to have a higher price than the FRR procurement if resources were to offer into the FRR procurement based only on conventional considerations.
- In a single-clearing price procurement (i.e., structured similarly to the BRA) a "rational" offer would be based on the higher of these *three* opportunity cost considerations.
- Creating circumstances where resources face incentives – as they may in an FRR procurement – to offer based on expected outcomes and not "true" costs threatens to create inefficiencies. This has long been the concern with "pay-as-bid" procurements.

	Offer Basis	Practical Observation
Avoidable Going Forward Costs		
CP Opportunity Cost		
BRA Opportunity Cost	A rational offer would consider the possibility of selling into the BRA, in which all demand would be represented and the price would be expected to be higher.	All else equal – and depending on the procurement rules – resources offering into the FRR plan will be expected to attempt to offer at the estimated BRA price, potentially plus an adder to account for uncertainty and additional administrative burden. Historically, forecasting RPM prices has been a fraught endeavor. CP risk pooling arrangements could also be a factor (discussed later in more detail).

FRR procurement design should attempt to reorient incentives so as to eliminate the need to for capacity resources to offer based on expected results.

Residual Capacity: Incentives & Procurement Design

Proposed FRR Residual Capacity Auction Structure

CRA proposes the following "straw man" auction design, which attempts to create offer incentives that will lead to efficient procurement outcomes. In short, this design is a pay-as-bid auction with a price floor at a pre-determined premium to the EMAAC price a set in the BRA. FRR Plan resources are selected in advance of the BRA, and final compensation levels are determined after the BRA is run.

Procurement Timing

- Procurement to take place ahead of BRA to ensure available capacity supply
- Were procurement to occur after BRA, only available supply would be high-cost supply not cleared in the primary PJM capacity auction

Supply and Demand

- Supply to be made up of offers from all resources eligible to sell capacity into EMAAC
- Demand would effectively be a vertical demand curve at the FRR procurement target

Market Clearing

- Sealed-bid auction
- The FRR procurement will establish which resources are to be included in the FRR plan (quantity), based on the lowest cost set of offers, but not the price that will be provided to contributing resources
- Cleared resources will be guaranteed the EMAAC price – determined in the BRA that follows – plus an adder (e.g., $5/MW-day), effectively creating an FRR price floor
- Resources that cleared in the FRR procurement but offered at price levels above the FRR price floor will be compensated on a pay-as-bid basis
- Potential to allow resources to offer to take a premium that is *lower* than the default premium, an offer parameter that could be used to break ties and could be used on a pay-as-offer basis to minimize capacity payments by NJ customers

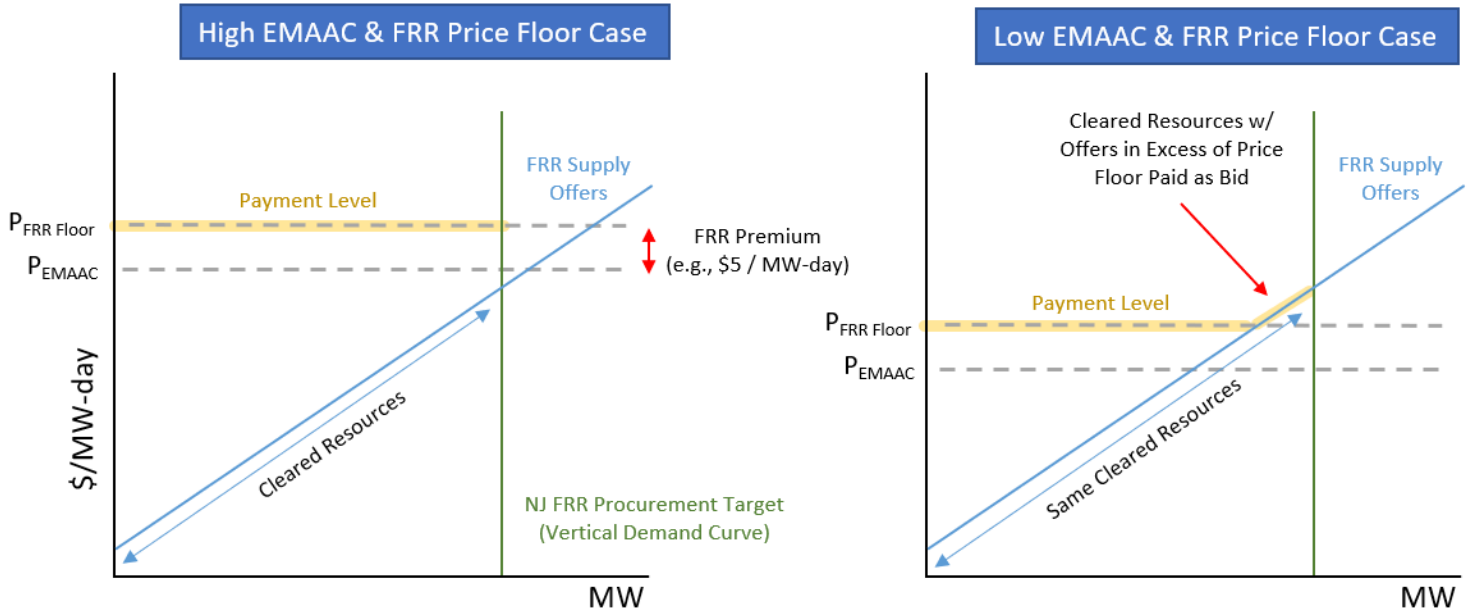
Locational Constraints

- PJM CETLs and minimum internal resource requirements will be respected
- No locational pricing or LDA "break outs"

Residual Capacity: Incentives & Procurement Design

Proposed Residual Capacity Auction Illustration and Incentives

The following illustrates the two potential pricing scenarios under CRA's "straw man" procurement design. In both cases, the FRR price floor is benchmarked to EMAAC pricing outcomes in the BRA after the FRR auction. In the High EMAAC price case, the FRR price floor is sufficiently remunerative for all resources necessary to fulfill the FRR requirement (left). If the EMAAC prices plus the FRR Premium is insufficient for certain resources procured in the FRR auction (e.g., high cost resources in PSEG), those higher cost resources receive their stated price offer from the FRR auction process (right).



- This auction design creates both incentives to participate and to submit competitive offers
  - Providing a guaranteed premium over the price available in RPM ensures that capacity resources are interested in participating – mitigating concerns over the opportunity cost of BRA participation – including being willing to take on incremental administrative burden associated with the FRR procurement process.
  - Providing a guaranteed premium for providing capacity creates an environment in which resources will compete to be included in the FRR plan and offer the minimum compensation they would be willing to receive (a "true" economic offer), which should align offer structures with those experienced in RPM proper.
  - The suggested design should eliminate incentives to offer above or below cost, both of which could lead to inefficient outcomes and both should be avoided with an effective design. Above cost offers risk resources missing an opportunity they would have been willing to take, and below cost offer risk resources taking on an obligation at a loss.

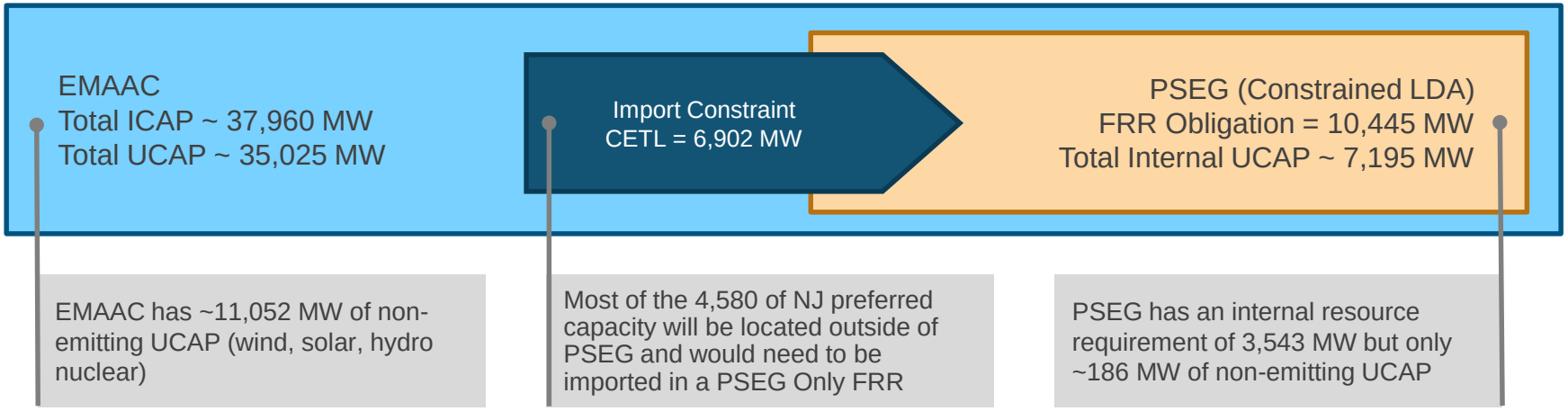
Residual Capacity: Incentives & Procurement Design

Residual Capacity Auction – Further Issues

Consideration	Discussion
Product Definition	• Product is UCAP, consistent with PJM definition. No bundled attributes. Uniform contracts across suppliers. • Term is one year, equivalent to RPM definition. This avoids challenges with structuring pricing with longer or differentiated commitment terms. Also, longer commitment terms are often justified to support new resources, and we expect that this auction would primarily procure existing resources.
RFP vs. Auction	• Given that the UCAP product is well-defined and resources are pre-qualified, we see no benefit of an RFP as opposed to an auction. An RFP could be used instead, but the results would be no more efficient and could be less efficient.
Auction Type	• Auctions for capacity are often discussed in terms of sealed-bid, descending clock, or a hybrid of the two. Here, because of the proposed pricing rules and the fact that the auction result is not a price but simply an identification of the resources to be designated in the FRR plan, a descending clock auction would not be appropriate as there is not a single clearing price result. • Sealed bid is also appropriate because the auction requires information about cost below the clearing quantity.
Pay-as-Bid Compensation (for some resources)	• Pay-as-bid is often disfavored over concerns about participants attempting to forecast the clearing price, which leads to inefficiencies, particularly for infrequent auctions like in capacity markets. As described, the straw man design should not face this shortcoming. • Pay-as-bid faces critique over paying resources different amounts to provide the same product, which may be considered unduly discriminatory. However, state default procurements frequently employ a pay-as-bid approach and pay-as-bid is more common in bilateral market environments. • Pay-as-bid also mitigates some concerns about market power, because high remuneration levels (resulting from exercise of market power) are not paid to all resources.
Appropriateness of long- and short-term incentives	• Incentives for efficient entry and (more importantly) exit should generally be maintained (though less relevant for RE), as pricing is ultimately pegged to RPM outcomes (to the extent RPM achieves these objectives) • Potential shortcomings around locational incentives, should constraints increase (lower CETLs).
Volume Risk and Procurement Contingency	• Given the newness of an FRR capacity procurement in a setting with primarily merchant suppliers, there may be uncertainty regarding whether sufficient volumes can be procured to fulfill FRR Plan requirements. • We suggest that this concern can be mitigated by robust procurement design, clear and early communication with potential suppliers, and process steps that include pre-showings of participation interest. • Selecting an FRR Entity with more limited residual procurement needs will limit this concern. • In any case, we suggest developing a contingency plan for such an outcome.

Residual Capacity: Transmission Considerations

- In addition to being a driver of concerns over market power, transmission constraints may be an issue for residual capacity procurement, particularly into the PSEG LDA and particularly if the goal of the residual capacity procurement is primarily to source residual capacity from non-emitting generators.
  - If PSEG is chosen as the FRR entity, a significant portion of the CETL would be consumed by importing "Tier 1" resources into the LDA (nuclear and OSW that interconnects to AECO and JCP&L). This would limit the ability to import clean Tier 2 resources across the interface, which would lead to including higher volumes of emitting resources in the FRR plan.
  - To a lesser degree, the same issue would apply in an All NJ FRR election, as a considerable portion of the obligation in PSEG and PSEG-N would need to be fulfilled by internal generation, much of which is conventional (fossil-fired).
- From an economic and reliability standpoint procuring residual capacity from emitting resources is not problematic, but there may be other considerations:
  - There may be perception issues related to a state procurement resulting in paying a premium to large(r) quantities of emitting resources (e.g., "New Jersey pays premium to support polluting generators").
  - It may be seen as desirable to send the FRR price signal, with the embedded premium, to resources seen as having more desirable environmental characteristics.
- This would not be an issue with a JCP&L or AECO FRR options, nor with the Partial FRR approach.



Note: RPM parameters based on 2021/22 BRA. Generation estimates based on CRA analysis of existing supply (source: Energy Velocity).

Market Power Considerations

- Market power issues are likely to be an emergent concern in the residual capacity procurement process, particularly if transmission constraints or strict resource qualification requirements (i.e., clean resource only) are in play.
- CRA generally recommends conservative, ex ante approaches to addressing market power mitigation in capacity-type markets given the persistence of outcomes (i.e., one year commitments) as compared to markets with more transient results (e.g., energy markets).
- On the following slides, we present a preliminary market power analysis to identify potential areas of concern for the PSEG LDA (relevant to the PSEG FRR and All NJ FRR cases) and the JCP&L LDA (relevant to the JCP&L FRR case). Given the very small quantity of residual capacity required in the Partial FRR scenario, we assume that market power issues will not arise in that case (very large supply base, very small demand).
- Because we observe that market power concerns may arise in some of the analyzed cases, we also provide suggestions as to possible approaches to ex ante screens and mitigation thresholds, but we do not attempt to be comprehensive nor do we recommend specific approaches.
- Given the high dollar values involved, the newness of residual procurement process, and the opportunity to improve successive procurements, we suggest it also advisable to retain an independent third party to review the auction process and results after each cycle to assess competitiveness and identify areas for improvement.
- Given the landscape of potential buyers and sellers, we expect that affiliate transactions are likely to result from the residual capacity procurement. Without giving a legal opinion, having the state administer the residual capacity auction and select suppliers should address Edgar concerns.
- Considering the appropriate geographic bounds of a market power analysis, we note that there is no prohibition on including resources from outside of New Jersey in the FRR Plan. Thus, where transmission constraints are not a concern (i.e., in the JCP&L case), we consider all resources in EMAAC as a potential source of supply (conservatively excluding resources in MAAC outside EMAAC and resources in PSEG).
- As pointed out by other commenters in the NJBPU proceeding, were an LDA to elect the FRR Alternative, such an action does not create market power where none existed before. Indeed, in some ways it may reduce market power (e.g., by decreasing demand). To the extent market power existed before and remained, the correct response is to design effective monitoring and mitigation procedures, not to be resigned to higher prices. Furthermore, while election of the FRR eliminates guardrails provided by the RPM rules, it creates the opportunity in install replacements that could likely be superior to the current PJM market monitoring and mitigation rules with their existing shortcomings.

Market Power Considerations

Quantitative Market Power Analysis

- CRA ran market power analyses for the three single-LDA FRR cases to provide insight into market power consideration for each scenario
  - Geographic market for AECO and JCP&L cases assumed to be EMAAC but excluding PSEG
  - Geographic market for PSEG case assumed to be PSEG only (and results translate to All NJ case, which includes PSEG)
  - Where possible, we constrained available capacity to only "clean" capacity supply (e.g., no coal, gas, or fuel oil)
  - For JCP&L and PSEG cases, we included a scenario where nuclear plants are included in FRR plan by default
- CRA ran preliminary residual supplier screens and Herfindahl-Hirschman Index ("HHI") tests for various scenarios
  - For the RSI screen, an RSI < 1 indicates a pivotal supplier (note that FERC uses the pivotal supplier test in its market-based rates analysis). RSI is applied on an individual and joint three-supplier basis (note the three supplier RSI screen is equivalent to the PJM MMU's three pivotal supplier test)
  - HHI indicates high levels of concentration in the AECO and JCP&L FRR cases, though this metric does not account for large total volume of supply relative to residual demand. In these cases, the RSI test results control and indicate no structural market power concerns.
- ***Preliminary results suggest there would be very little concern related to market power in the JCP&L and AECO FRR scenarios, even if residual supply were limited to clean resources, though if nuclear units are not included by default the RSI screens are tighter.***
- ***Preliminary results suggest that market power would be a concern in the PSEG FRR and All NJ FRR scenarios, which indicate that, if one of those approaches is selected, then additional attention should be paid to market power monitoring and mitigation rules in the residual capacity procurement process. Also indicates increased levels of risk that high prices will result.***

Case	One Supplier RSI	Three Supplier RSI	HHI (clean energy)	HHI (all supply)
JCP&L FRR (Nuclear plants in FRR)[1]	4.58 (Clean -Pass)	3.62 (Clean - Pass)	5,338 (Highly concentrated)	1,356 (Unconcentrated)
JCP&L FRR (No separate nuke treatment)	2.04 (Clean - Pass)	1.24 (Clean - Pass)	4,589 (Highly concentrated)	1,412 (Unconcentrated)
AECO FRR (No separate nuke treatment)[2]	5.63 (Clean - Pass)	3.42 (Clean - Pass)	4,589 (Highly concentrated)	1,412 (Unconcentrated)
PSEG FRR (Nuclear plants in FRR)	0.91 (All - Fail)	0.69 (All - Fail)	N/A[3]	4,323 (Highly concentrated)
PSEG FRR (No separate nuke treatment)	0.94 (All - Fail)	0.8 (All - Fail)	N/A[3]	4,323 (Highly concentrated)

Note 1: Assumes nuclear plants are included in FRR Plan by default and not procured as part of residual capacity procurement
Note 2: No AECO case for separate nuclear treatment because AECO capacity requirement not large enough to absorb nuclear capacity
Note 3: No clean energy only option for PSEG owing to insufficient internal supply of clean energy capacity in PSEG LDA

Market Power Considerations

Monitoring and Mitigation Options

There are generally two elements to active monitoring and mitigation of seller market power in capacity markets:

Screening

Identifies particular capacity suppliers that have the potential to exercise market power. Options include:

- One-pivotal supplier test (less conservative)
- Three-pivotal supplier test (more conservative)
- Market share thresholds

Suppliers that fail these screens are subject to mitigation.

Screens like an HHI test can also be applied to assess the competitiveness of the market as a whole.

Mitigation

Sets a maximum default offer price level for mitigated sellers. In this context, mitigation ceilings could be set at, for example:

- Minimum EMAAC price from recent years (more conservative)
- Prior year EMAAC price, or recent historical average
- Forecasted EMAAC or PSEG price (more complex and controversial)

In any case, to avoid concerns about over-mitigation, resources should have the option of making resource-specific showings to justify offers above the mitigation threshold

- Market power monitoring and mitigation responsibilities may be taken on by the auction administrator or shared with or assigned entirely to a third party. One potential structure would be to have the administrator run any screens and implement mitigation thresholds, with an experienced third party utilized on an as-needed basis to review resource-specific cost showings. We note that FERC may require some showing of mitigated market power in approving an FRR Plan. Certainly, this is an area where considerable attention would be required in the design phase.

- The above generally address concerns over economic withholding or attempts to affect price via offers that reflect an exercise of market power rather than economic fundamentals. They do not address physical withholding, which is frequently addressed via must-offer provisions and could be an issue in a residual capacity auction. To manage this issue in a NJ residual capacity procurement process, we would recommend exploring whether generators situated in the state could be required to offer into the FRR auction, similar to common “must offer” requirements.

Risk Management
General Considerations

In our assessment, and consistent with statements from PJM, there are two main types of risk assumed by the FRR Entity:

Capacity Resource Deficiency Charges	Should a (supply) counterparty in the FRR plan be for some reason unable to fulfill its obligations and count towards the FRR Entity's FRR obligation, the FRR Entity will face deficiency charges equal to 1.2 x the locational resource clearing price from RPM (assessed daily)
Capacity Performance Provisions	Resources included in the FRR plan are still subject to CP rules, though two options are afforded: 1. **"Financial" Option:** Resources in the FRR plan are subject to CP bonuses and penalties on the same basis as all other capacity resources, though the FRR Entity holds the responsibility, not the individual supply resources 2. **"Physical" Option:** The CP penalty and bonus structure does not apply. Rather, if the pooled resources in the FRR Plan experience a shortfall during performance events, the FRR must procure additional capacity in the future to meet its FRR obligations in a quantity reflecting the level of underperformance

- In considering risk and risk sharing associated with the FRR Alternative, it is our view that it should be recognized that the FRR LSEs are taking on the FRR, and the associated risks, on behalf of all NJ ratepayers and not as an elective benefit to the utility or its customers.
- Consistent with the above, and subject to prudence review, we would suggest that risk mitigation needs to be considered early on in the FRR process and be appropriately allocated to generators and/or all NJ ratepayers, and not solely to the FRR Entity and/or its customers. This can be arranged through regulation and contract terms.
  - For capacity deficiency charges, should they arise, the associated costs can be allocated by the same mechanism as the rest of the FRR costs.
  - For CP charges, there are several options to consider. (See following slide)

Risk Management

Addressing Capacity Performance

The following are what we view as the most promising alternative approaches for managing CP risk within an FRR plan. The proposed arrangement would be represented to potential suppliers as part of the procurement process such that suppliers would be aware of their expected risk profile in advance and reflect that in their offers. Risk transfer would be achieved via contract. Per the PJM rules, conveyance of CP price signals and risk pooling would be administered by the FRR Entity and not PJM.

Elect Financial Option w/ No CP Risk Pooling, Risk on Suppliers

- Maintains incentives created by CP rules for individual suppliers to improve availability and performance during performance events
- All CP risk passed to suppliers as if they were any other PJM capacity supplier
- CP risk to suppliers may be expressed in supplier offers and capacity procurement costs

Elect Financial Option w/ Pooling Only Among Renewables (Recommended)

- Maintains incentives created by CP rules for emitting suppliers (residual capacity, nuclear)
- Reduces risk for renewable resources (wind, solar) that have limited ability to control output during performance events
- Net penalties could be allocated either to all renewable resources or, more likely, to ratepayers
- Potentially reduces renewable procurement cost by helping to mitigate embedded CP risk

Elect Financial Option w/ Pooling Across All FRR Resources

- Reduces risk for individual suppliers
- Raises concerns over free-riding by less reliable suppliers on more reliable suppliers
- Imposes additional costs on either ratepayers or more reliable generators

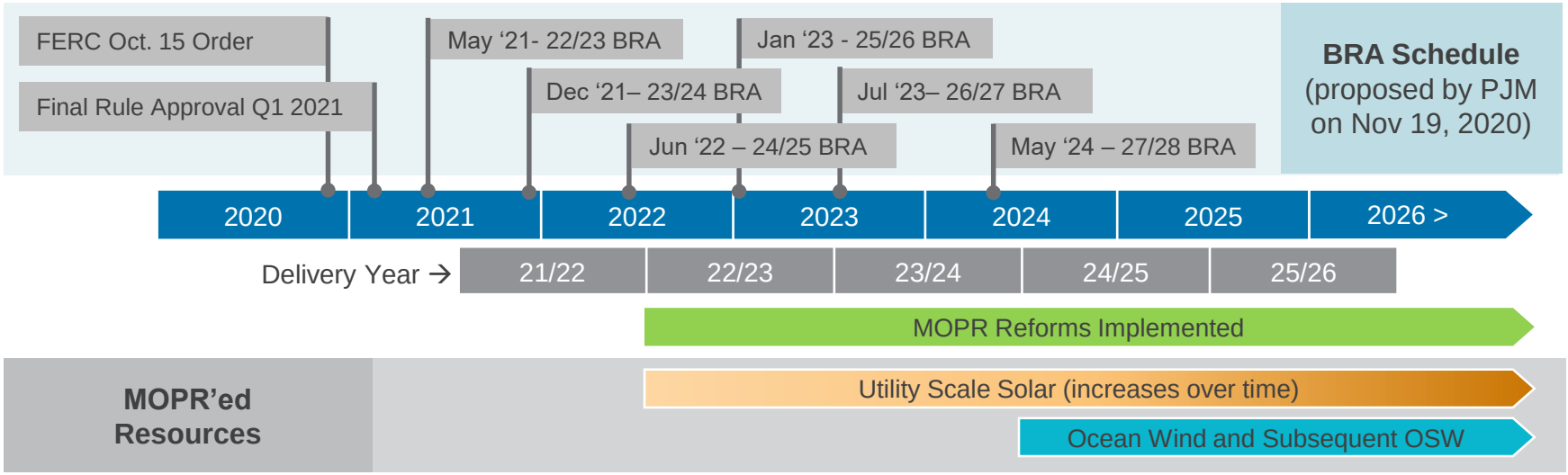
Elect Physical Option

- Eliminates incentives for performance created by CP rules for individual suppliers
- Ratepayers would ultimately bear cost of requirement to procure additional capacity for future delivery period
- Potentially reduces procurement costs because FRR suppliers no longer face CP risk
- Simple to administer

Note: Another approach (not listed above) would be for the FRR Entity to elect the financial option but take all CP risk upon itself and its ratepayers. Particularly with the proposed residual procurement design, which ties the product and the price to RPM outcomes, we see little benefit to such an approach. It would be potentially highly financially burdensome to the utility while also failing to convey the CP signal to generators.

Other Issues

Implementation Timing

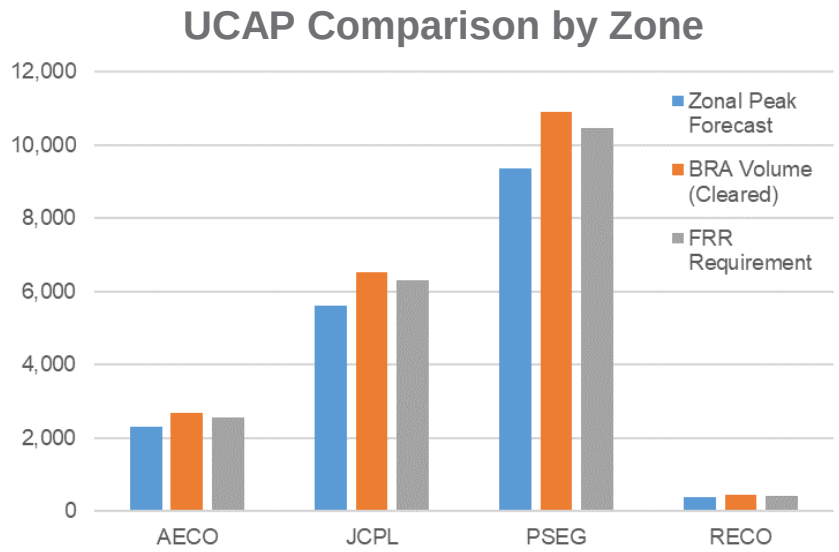


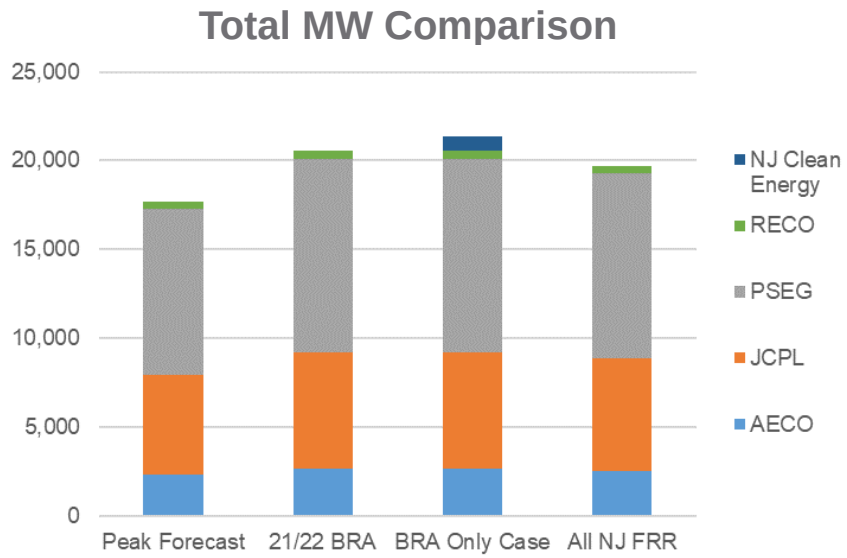
- Should New Jersey elect an FRR Alternative, a remaining question would be in which delivery period to start:
  - **As soon as possible** (i.e., for the first delivery period under the new MOPR rules – 2022/2023): This would require rapid development and implementation of procurement rules, but would eliminate any concerns about near-term duplicative procurement and associated charges to NJ ratepayers. Might also allow for NJ to design near-term renewables procurements to be compatible with FRR structure.
  - **2024/25 delivery period**: This approach would allow for a less time-constrained FRR development process, while completing the FRR election in time for the expected COD of Ocean Wind, a key milestone for concern over duplicative capacity procurement. Following 2024/25, duplicative procurement and cost impact concerns are only expected to become more severe as time goes on.
- Delaying the FRR election to 2024/25 would probably have only a minor cost impact as the only duplicative procurement would be associated with utility-scale solar procured in earlier delivery years. More major cost impacts would expected coinciding with COD for Ocean Wind and increased buildout of subsidized storage.
- Delaying the FRR election would be expected to lead to very moderately higher BRA prices in the interim, which may have the effect of delaying retirement of older, higher emissions generation.
- When PJM has its rules approved and starts running BRAs again, RPM events (including incremental auctions) are going to be frequent and market participants will have a lot to keep track of, which should be accounted for when developing the FRR procurement process and deciding on timelines. An unremarkable result (e.g., low prices) in the 2022/23 BRA could also dampen FRR momentum, though it should not.

Other Issues

Reliability Implications

- In any case, “resource adequacy” as defined by PJM per the RAA rules is almost certain to be achieved given market design and current levels of supply.
- Electing the FRR, in any form, would be expected to technically lead to a decline in reliability, as aggregate volumes of capacity would be lower.
  - The BRA generally clears capacity in excess of the FRR UCAP obligation owing to the use of a sloped demand curve and the general conditions of oversupply in the PJM footprint.
  - The presence of un-counted capacity in the status quo case – resource subsidized by NJ but MOPR’ed by PJM – would contribute to reliability in excess what would be provided solely by UCAP volumes procured via RPM.
  - The most aggressive FRR case – the all NJ FRR Case, shown below – would have the largest impact of this form.
- A counteracting pressure of lower reserve margins is that generator operators – who know that CP events will be more likely – may respond by making adjustments that increase their availability and thereby improve reliability (and vice versa if there are higher reserve margins).
- Should the FRR Alternative be elected by numerous states or utilities, it is possible that rules would change to increase FRR procurement requirements such that FRR Entities cannot be accused of “leaning” on the rest of the PJM system from a resource adequacy standpoint (e.g., by increasing FRR UCAP targets to match historical RPM outcomes).





Other Issues

Residual Procurement Administration and Administrative Costs

- The FRR residual procurement process could be run by either the BPU or the FRR Entity itself. The latter is an option particularly if the FRR Entity is a single utility.
  - The PSEG/Exelon proposal suggests this procurement would be run by the BPU, which supports process independence and removes concerns over affiliate transactions (Edgar standard).
  - A number of factors indicate that the FRR Entity, particularly if a single utility, could best be positioned to run the procurement:
    - A utility acting as the FRR Entity would likely prefer to have control over capacity procurement for which it would ultimately be the contract counterparty.
    - We understand that the BPU has a preference for deferring on matters like running procurements, and could potentially play an oversight and evaluation role rather than being directly responsible for the whole process.
    - This approach would limit administrative burden and bureaucracy associated with working process steps through the BPU.
    - Edgar concerns could be addressed via procurement design and implementation that exhibit competitive design, lack of undue preference, lack of favor for affiliates, and a reasonable combination of selection factors. Our proposed strawman procurement should facilitate this.
  - To support independence and fair evaluation, we suggest that a third-party consultant could be hired to run the procurement process.
  - To ensure transparency and oversight, certain reporting requirements could be put in place or an independent monitor could be hired to assess process and results.
- Implementing an FRR Alternative for NJ utilities would entail administrative expense, though much smaller than cost differences across the various alternatives analyzed here.
  - Auction administrator costs: the entity that runs the FRR procurement (e.g., the utility that is the FRR Entity) will incur costs for design, implementation, market monitoring, etc. Should the administrator be a government entity, existing funding mechanisms may be used.
  - Utility administration costs: the FRR Entity will ultimately need to implement the FRR Plan following the results of procurement, including interfacing with PJM, contract implementation, and ongoing FRR management tasks (e.g., arranging replacement capacity, if needed). These costs will need to be recovered through rates.
- To the extent that one or more NJ LSEs are selected to implement the FRR Alternative – as discussed prior – it should be recognized that those LSEs are taking on the associated burden on behalf of all NJ ratepayers and not as an elective benefit to their customers.
  - The cost burden of FRR implementation should therefore, so the extent possible, be spread across all NJ ratepayers so as to not be unduly burdensome to the customers of the FRR Entity.
  - Cost recovery on the part of the utility should be allowed for associated expenses, and this should be provided for in legislation and/or regulation that calls for FRR implementation.

Other Issues

Considerations Should Other States Elect FRR Alternative

- Should other whole states or specific LDAs elect the FRR Alternative, that may affect the suite of considerations in play associated with a New Jersey FRR decision-making process. Other states for which the PJM IMM has run FRR scenarios include Ohio, Maryland, and Illinois. We also understand that Virginia is actively considering an FRR election.
  - In the cases of Ohio, Illinois, and Virginia, we see little that would affect our analysis or recommendations related to the New Jersey FRR. While there would be potentially large changes to RTO and MAAC capacity pricing, based on the IMM's analysis transfer constraints should mitigate pricing effects within EMAAC. Thus, the relative relationship we have calculated between the RPM case and the FRR scenarios should persist.
  - The possibility of a Maryland FRR election would be more relevant to the FRR decision in New Jersey. Maryland would have similar options to New Jersey in terms of FRR scenarios – the FRR could be a single utility, a partial FRR, or the entire state. Situated (partially) within the EMAAC LDA, the IMM calculates that some of the studied scenarios Maryland FRR would lead to declines in EMAAC price.

- Some potential interactions between a Maryland FRR and a New Jersey FRR include:
  - Lower EMAAC prices would lead to decreased RPM reference prices. If residual procurement compensation is tied to EMAAC prices, this could further reduce residual procurement cost.
  - If residual procurement constructs in both MD and NJ FRRs target non-emitting resources, that could increase competition and potentially increase concerns over exercise of market power. This concern would be more acute the larger the residual procurement target, though we again note that clean-supply within EMAAC is relatively plentiful and unconcentrated.
  - Depending on residual procurement design and process schedule, unusual incentives could be created for potential residual capacity sellers in considering participation and offer strategies.

- Unknowns and potential undesirable interactions between simultaneous and geographically adjacent FRR elections appear to largely revolve around the effect on residual procurement. This could be viewed as a further reason for FRR incrementalism, as incremental approaches (e.g., single-LDA FRR scenarios or Partial FRR) limit residual procurement volumes and cost exposure.
  - We expect that undesirable interactions across FRR structures could be mitigated by cross-state coordination and effective procurement design.
  - We further note that it is conceivable that were only one state to elect an FRR subsidized resources from both states could sell into that FRR to realize the value of their UCAP - subject to any relevant CETL constraints.