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Considering the Evolution of PJM's Capacity Market

Suggestions for RPM reforms in a post-MOPR World

By Jordan Kwok, Charles River Associates

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Introduction

At long last, PJM's revised minimum offer pricing rules ("MOPR") have been finalized and the first capacity auction in years, to be held in late May 2021, is nearly upon us. And, yet, as soon as the ink was dry approving PJM's rule changes, discussions began about how to roll them back. Not only is it now widely expected that the Expanded MOPR will not survive more than a single auction, PJM and the Federal Energy Regulatory Commission ("FERC") have launched a broader discussion about how capacity markets, including PJM's, need to be reformed in the face of an evolving electricity sector. This whitepaper touches on the impact and fate of the soon-to-be-defunct Expanded MOPR. It then lays out a range of areas where stakeholders might consider reforms to the current PJM market rules that would improve market efficiency, with a focus on the implications of an evolving energy mix and the incentives faced by capacity sellers. Topics include:

- Reconsidering PJM's current three-year forward period in favor of a prompt auction
- Taking steps to improve market transparency and guarding against over-complexity
- Rationalizing the capacity market demand curve, particularly the reference resource
- Preventing positive reforms from being slowed by concerns about seller market power
- Continuing efforts to better align market rules with the product being transacted

In a market like PJM with mandatory physical reliability standards (i.e., one-in-ten), capacity markets are almost certain to remain a necessity to maintain resource adequacy. While too much tinkering can be troublesome, if there is a re-evaluation of PJM's capacity market as it currently stands – rather than a more dramatic change to a new paradigm – this paper suggests consideration of the issues highlighted here.[1] Getting the rules right is important to ensuring the market achieves the objectives of supporting efficient entry and exit decisions, which together should support the cost-effective provision of resource adequacy for customers.

Status Update: In the End as in the Beginning

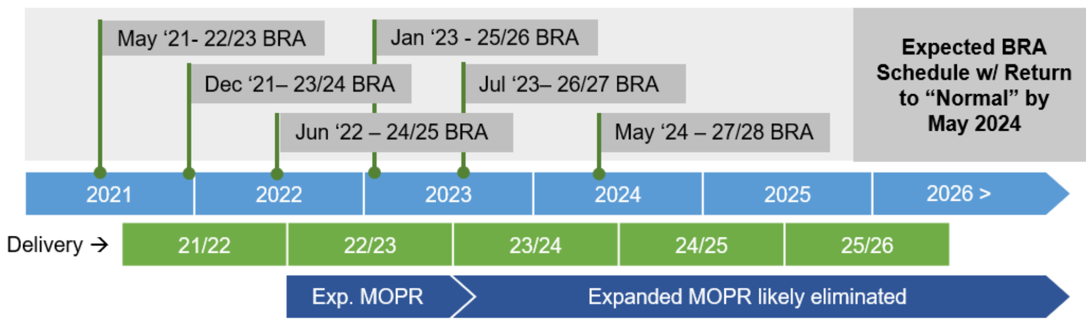
Dating back at least to 2016, FERC and PJM have been grappling with stakeholder concerns regarding alleged "price suppressive" impacts on capacity market prices resulting from state subsidies for favored generation resources, both existing and new. After one of the most fraught proceedings in recent memory – one spanning three presidential administrations and seven FERC Chairs – PJM finally has, for better or worse, a set of FERC-approved capacity market rules that ostensibly mitigate the impacts of the offending offer behavior. While the details are numerous and important, the ultimate effect is to set minimum offer price thresholds – what is now being called the "Expanded MOPR" – for any new resources receiving state subsidies, as well as for existing *conventional* resources (i.e., coal and nuclear) receiving state subsidies. The Commission reasoned

[1] Over the long term, RPM may need to be revised entirely, rather than simply evolved, to better fit with a supply mix that is far less centered around conventional, dispatchable resources. Though considerations suggested here may be relevant to such a redesign, the goal here is not to present an entirely new framework.

that this change would protect the competitiveness of the PJM capacity market (called the Reliability Pricing Model, or "RPM").

With its new, approved rules, PJM is free to start running capacity auctions again. Most immediately, the Base Residual Auction ("BRA") for the 2022/2023 delivery period will be run in late May 2021, with auction results expected June 2, 2021. Following this BRA, PJM will proceed with its "catch-up" period, running BRAs approximately every six months with an adjusted incremental auction schedule to account for the adjusted forward periods resulting from the compressed auction timeline. Under this plan, PJM will be able to return to its standard auction timing by the 2027/2028 BRA to be held in May 2024.

Figure 1: Expected RPM calendar through return to standard BRA auction schedule



With all the MOPR rule changes in place at last, and after an exhausting administrative process, there is an irony to the fact that very little is likely to change as a result of the Expanded MOPR in terms of market impacts and pricing dynamics. In the next few auctions, at least. In terms of *existing* subsidized resources that face meaningful offer mitigation, there may be none. Following the repeal of nuclear subsidies provided by Ohio HB6, there are zero nuclear generators in the PJM footprint that will face restrictive Expanded MOPR offer thresholds as a result of state subsidies received.[2] In terms of *new* subsidized resources that could be subject to the Expanded MOPR and excluded via mitigation (i.e., MOPR'ed), most that could have been MOPR'ed will be grandfathered in, owing to having been sufficiently far along in the interconnection process at the cutoff date (December 19, 2019). Of the resources that are not grandfathered, based on CRA's work with clients and statements by PJM[3] and PJM's Independent Market Monitor ("IMM") regarding the competitiveness of renewables, there appears to be a good chance that solar generators will be able to justify resource-specific price floors that are low enough to ultimately clear.[4] Onshore wind resources may also be able to achieve this result, but

2 There may be several coal units in Ohio that face MOPR offer floors greater than $0/MW-day – owned by the Ohio Valley Electric Corporation and receiving payments under HB6 – but those floors are likely below anticipated clearing prices.

3 See PJM's comment in AD21-10, noting that Offshore wind are least likely to clear under the Expanded MOPR, while new sola rand wind resources may be able to clear with unit-specific floor prices.

4 For example, adjustments to several key CONE parameters from default values to values being observed in the marketplace (e.g., lower costs of capital and debt and longer asset life) can drive the calculated net CONE for utility-scale solar with tracking well below $70/MW-day.

there is more uncertainty around this outcome.[5] It is possible, if not likely, that *no resources* will be precluded from clearing in the first BRA following the implementation of the Expanded MOPR reforms.

But what about later auction years under the Expanded MOPR? If the Expanded MOPR as it currently exists survives, and absent any new subsidies for existing single-unit nuclear plants, future results would likely be similar for nuclear – in that they would not be excluded via available offer floors – and potentially for solar resources as well, depending on the results of the resource-specific review.[6] This leaves the MOPR as narrowly targeting offshore wind, storage, and potentially some onshore wind and distributed energy resources as technologies that, if receiving state subsidies, would face offer floors that could preclude them from clearing the BRA. Thus, the resultant price impacts could become meaningful starting as early as the 2024/2025 BRA, when New Jersey and Maryland offshore wind resources are slated to enter service, with the accompanying concerns about increased customer costs and encroachment on state jurisdiction over electric generation.[7]

Of course, this concern about the future begs the question about whether the Expanded MOPR will survive. At this point, it is very likely it will not. The current leadership of FERC has been openly critical of the rules that are now in force[8] and PJM has stated “the current MOPR is not a durable solution and needs reform.”[9] Both entities are currently undertaking public processes to discuss how to scrap the recently-approved reforms and, more broadly, how resource adequacy constructs need to evolve to better align with the evolving power sector in the US. Indeed, PJM has already initiated a Fast Path process to file a revision of the Expanded MOPR in July 2021.[10] This seems likely to result in a phased repeal and reform process – with a simple repeal of the Expanded MOPR before the December 2021 BRA for the 2023/2024 delivery period. This would be followed by a more comprehensive reform process that would apply to later auctions. The remainder of this whitepaper provides discussion on a range of topics that should be considered as part of any broader set of improvements to RPM.

5 While public documentation on the resource-specific exemption process is not forthcoming, the PJM Market Monitor has made repeated public comments about the demonstrated competitiveness of renewable technologies. See, for example, comments of Dr. Joe Bowring at FERC’s March 23 Technical Conference (transcript pg. 76).

6 Market participants report that the resource-specific review process for the 2022/2023 BRA “has proven to be costly, labor-intensive, inconsistent, and non-transparent” (AEE Comment in RM21-10) and that it was “arduous, labor-intensive and administratively unworkable” (American Clean Power Comment in RM21-10). Thus, there is room for considerable uncertainty as to whether resources, particularly new solar generators, will be allowed to participate on a basis that allows them to accurately reflect their costs in their capacity sell offer. This uncertainty is particularly troubling if the Expanded MOPR were to persist, as an unreliable resource-specific review process could harm both generation developers and the broader efficacy of the market.

7 The customer cost concern is multi-faceted, but largely revolves around the expense of duplicative capacity procurement. One set of resources will be procured by RPM, while another will be procured to meet state clean energy policies.

8 See, for example, comments of Chairman Glick at FERC’s March 23 Technical Conference (transcript pgs. 6-9).

9 Statement of PJM Interconnection, FERC Technical Conference on Resource Adequacy in the Evolving Electricity Sector, March 23, 2021.

10 https://insidelines.pjm.com/pjm-mopr-reform-talks-start/

Reconsidering RPM's Forward Period

The US power sector has entered a period of intense transition. This transition will probably be marked by further decline in coal generation and continued reliance on natural gas, as well as rapidly increasing renewable generation, bulk storage deployment, increasing EV use, continued energy efficiency improvements, and growth in distributed energy resources and increased demand side participation as interconnected devices become more common. As these changes unfold, the combined impact adds yet another reason—the ability to adapt more quickly to changing system conditions—to reconsider RPM's already-questionable three-year forward period. For reasons explained below, a prompt capacity auction approach is likely superior.

First, consider the status quo. Traditionally, there have been several interrelated arguments in favor of longer capacity procurement forward periods. These arguments include:

- Support coordination among competing suppliers;
- Support execution of necessary long-term utility planning functions;
- Provide ample lead time to develop new generation that clears in the forward auction, including facilitating financing efforts by granting capacity revenue certainty; and
- Allow the threat of new entry to discipline the offer market behavior of incumbents.

This paper addresses each of the above in turn, concluding that, on further examination, they are not well supported based on practical considerations and empirical evidence.

The first set of arguments are based on the notion that commitments associated with forward capacity procurement better allow for coordination among capacity suppliers and support other necessary utility functions, particularly transmission planning.[11] On the topic of capacity supplier coordination, it is not clear exactly how this would be realized in practice. It is possible that revelations from individual auctions, in the form of lists of cleared resources or details about the supply curve, may lead resources to alter their long-term decisions. However, the paucity of auction transparency currently offered by PJM likely limits this possibility, as discussed in later sections. To arguments about the benefits to other utility processes, having a three-year forward period is hardly the only way that planners can gather the necessary information on expected supply resources. The generator interconnection process may be the more appropriate and effective venue for gathering such information. Indeed, RTOs like CAISO and NYISO are able to accomplish these network planning exercises without three-year forward capacity commitments.

The second and more frequently stated argument is that a longer forward period allows sufficient lead time for capacity sellers to develop resources in the period between clearing in a capacity auction and entering service in time for the delivery period. Specifically, the

[11] See, for example, James Bushnell, Michaela Flagg, and Erin Mansur, "Capacity Markets at a Crossroads," April 2017, p. 40. (https://hepg.hks.harvard.edu/files/hepg/files/wp278updated.pdf)

argument has been that three years is approximately the time it takes to bring online a new gas-fired power plant.[12] Relatedly, providing this forward period would allow for more active participation by new entrants in a contestable market, wherein they could offer speculative bids that, if cleared, would be developed. Such competition could discipline market behavior by incumbents, who might otherwise seek to manipulate prices in a highly concentrated competitive environment. If accurate, it would stand to reason that there would be positive correlation between high-price auctions and new entry, and that shorter forward periods would impede development of new generation. However, this is not what the data shows. Furthermore, the underlying logic, while appealing at a surface level, makes little sense in practice.

The key insight needed to understand why this reasoning does not hold is that developers of new resources do not make decisions based on a single auction outcome. Rather, merchant developers make decisions based on long-term expectations for capacity prices (and energy prices). Long-lived assets are not developed on promise of a single year of capacity revenue, nor should they be. Put in perspective, one year represents only 5% of the operating life of a 20-year asset, and many operate for much longer.[13] Accordingly, developers make build decisions based on long-term price forecasts, as later-year price outlooks should dominate the investment decision. If the expected outlook for capacity, combined with other revenue streams, is sufficient to recover costs and provide an acceptable return on equity, then a generator will likely be built.

Following the decision to go forward with a new generation project, asset owners are generally expected to offer into capacity markets as price takers for most of the early years of the asset's life, with the aim of securing the capacity revenue stream at any level. In this way, the presence and predictability of the capacity market *over the long term* provides the support necessary to develop a new resource. Only when avoidable going forward costs rise meaningfully should resources be expected to do anything but offer into capacity markets as price takers, accepting any available capacity revenue available from the market.[14] In that sense, a specific year's capacity price is not for new resources; rather,

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12 New resources may face substantial risk that they will not successfully complete development processes to achieve entry within only three years after taking on an obligation. This may cause some investors to incur substantial costs (e.g., engineering design and securing permits) prior to the auction, in part to reduce risk that a new supplier faces related to completing its project by the start of the delivery year.

13 On a discounted basis, first year capacity revenues could amount to 10% or more of total present-value capacity market revenues. This adjustment does not change the conclusion that a single year of capacity revenue expectations is only a fraction of what is required to support asset financing.

14 In theory, with the capacity performance ("CP") rules in place, resource offers should also reflect the opportunity cost of declining a capacity obligation in favor of the potential benefit of receiving larger bonus payments during a CP event. In practice, between the scarcity of CP events and an expected preference for a certain revenue streams (capacity payments) over uncertain ones (CP bonus payments), CP appears to have had very little impact on offer behavior. This is based on resulting capacity prices and what little information is available about the shape of the RPM supply curve.

it is a signal for retiring resources. Put another way, the *structure* of the capacity market supports resource entry decisions and *individual auction prices* support exit decisions.[15]

A similar framing of the multi-year forward period argument is that a capacity obligation, and the associated promise of capacity revenue, is necessary to secure financing for new generation projects. In CRA's experience working with clients on transactions associated with development of new power plants, this is also not the case. Again, contributors of equity and debt are concerned about revenue outlooks across an asset's life and focus more on long-term capacity price forecasts, and other drivers of plant margins, than on capacity price in the first year of a new resource's service life, or the possession of a capacity obligation prior to development.

Empirical evidence to support this point abounds. Again, NYISO and CAISO have maintained resource adequacy in a restructured environment and without a capacity construct with a multi-year forward period.[16] Moreover, the recent delay in PJM auctions provides a natural experiment on this topic. As shown in Table 1, despite the shorter forward periods for 2022/2023 and 2023/2024, the PJM footprint has more than 9,000 MW of generation in late development stages – both conventional and renewable – that is expected online without capacity auction results or commitments. CRA analysis also shows that, of the combined cycle ("CC") units that entered service since 2010, at least 5,100 MW of that capacity began construction and another 2,200 MW had begun site preparation activities 36 months or more ahead of commercial online date ("COD").[17]

Table 1: Permitted and under-construction generation in the PJM footprint for yet-uncleared capacity delivery periods[18]

	COD for 2022/2023		COD for 2023/2024	
Status	*Summer MW*	*Units*	*Summer MW*	*Units*
Permitted	2,210	20	1,540	40
Under Construction	3,990	7	1,420	4
Total	**6,200**	**27**	**2,960**	**44**

Source: CRA analysis of Energy Velocity data

15 Stoft and Crampton make a similar observation, "Short-term capacity markets could pay hourly and would work fine, provided investors believe the payments will continue. In that respect long-term markets have little advantage." Peter Cramton and Steven Stoft, "The Convergence of Market Designs for Adequate Generating Capacity." White Paper for the Electricity Oversight Board, 2006, p. 52.

16 This is not to suggest that either resource adequacy construct is without challenges. However, at least by NERC's assessment criteria, both regions have been consistently assessed as maintaining reserve margins in excess of the reference margin level. (https://www.nerc.com/pa/RAPA/ra/Pages/default.aspx)

17 While less data is available on permitting processes, for the plants for which it is available a majority of CCs developed in this period had been at least partially permitted more than three years in advance of COD.

18 Plants with CODs in March or after are associated with capacity market entry in the following June. For example, a plant with a COD of March 1, 2022 is assumed to take on its first capacity obligation in the 2022/2023 delivery period. Major under-construction CCs and CTs with COD for 2022/2023 include Apex Power Guernsey Power Station (Ohio, CC), J-Power Jackson (Illinois, CC), Indeck Niles Energy Center (Michigan, CC), and C P Crane (Maryland, CT). In terms of COD for 2023/2024, the largest conventional under-

There is also a sequencing problem in the three-year-forward logic. A high capacity price resulting from a single BRA – for example, one at or approaching the net cost of new entry ("CONE") – may indicate that the market is relatively short capacity. However, any remedy is necessarily delayed. Such is the nature of an annual auction. Once that high capacity price has been established, the associated auction is then past, along with the forward period that is ostensibly necessary to develop a new generation resource in response. This dynamic might be different if BRA prices were good indicators of expectable Incremental Auction ("IA") results – indicating perhaps that a resource should begin development immediately after a high BRA price on the promise of being able to enter capacity at a similar price in a later IA. However, IA pricing results have historically been quite a bit lower than those of the associated BRA.

Now consider retirement decisions, the other key judgment that is, in theory, facilitated by the capacity market. A resource will rationally retire, or at least mothball, if it does not expect to earn enough revenue in the capacity and energy and ancillary services markets to pay for the avoidable going forward costs of continued operation. Such resources are generally towards the end of their economic lives. They are probably fully amortized and may have very limited recurring fixed costs. Their owners may intend to operate them, receiving associated capacity revenues and little else, until they suffer a major equipment failure or face some other capital-intensive decision point. At that time, they would be expected to decide to retire or mothball depending on capacity auction results, and whether associated revenues over the short-term would justify the cost of a needed repair.

While multi-year forward procurement appears to do little to support the new investment process, it may considerably harm efficient retirement decisions. In a three-year forward procurement, owners of resources facing retirement must determine whether old resources will continue to operate for an additional four years (three years forward plus the capacity delivery year). Given their operating posture, these units face substantial physical and regulatory uncertainty on a year-to-year basis. It is not optimal for them to commit so far forward to taking on a capacity obligation when events during the multi-year forward period could so significantly affect their business conditions. Thus, a well-functioning prompt auction would better allow existing suppliers to make well-informed and rational economic decisions regarding when to suspend or retire a unit.

To recap, to the extent investment decisions in both forward and prompt auctions are based on future expectations, the forward market does not appear to offer any benefits over the prompt auction from the perspective of facilitating new investment. With regard to retirement or mothball decisions, a prompt auction arguably provides a price signal that is much more timely and well-aligned for the resources at or near retirement, to which the capacity price in any given year is relevant. Acknowledging the limited benefits of forward

construction generator is CPV Three Rivers (Illinois). One other large CCs is permitted: Clean Energy Futures Trumbull (Ohio). Of note, Jackson's MOPR status and treatment are at issue in EL21-62. Storage units are counted in unit count totals but not MW figures. For context, by PJM's accounting, as of the 2021/2022 auction, approximately 39,000 MW of new installed capacity has been developed in PJM since RPM was implemented. (https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2021-2022/2021-2022-base-residual-auction-report.ashx) procurement, it is useful to recognize the range of other benefits offered by prompt auctions:

- **Reduces demand forecast uncertainty**: PJM has historically struggled with load forecasting, resulting in systematic over-procurement in the three-year forward BRAs. Reducing the forward period limits the reliance on demand forecasts three years forward. Furthermore, load forecasting is likely to become more challenging as system conditions rapidly evolve with new technology deployment, changes in resource mix, and shifts in demand patterns. These changes are likely to disrupt the historical relationships between macroeconomic indicators and peak demand that are relied on in PJM's load forecasting methodology.
- **Increases certainty about available supply:** Prices resulting from a prompt auction should better reflect current supply and demand conditions in the market. For example, should a resource suffer a catastrophic failure that leads it to be out of service for an extended period, the supply curve and prices will reflect that in the prompt auction. Similarly, prompt auctions limit exposure to risks associated with delays in development of new resources, as those resources have not sold forward and will not need to be replaced if they fail to meet development milestones.
- **Improves alignment of auction timing with delivery period conditions**: A three-year forward period creates a three-year mismatch between implementation of any changes to auction parameters, market rules, or offer behavior and actual delivery of capacity. For example, changes to the federal tax rate can meaningfully impact calculated net CONE values, but the forward period leads to a considerable lag before the change is reflected in settled capacity revenues, which in turn may meaningfully harm either consumers or producers depending on the direction of the tax changes.[19]
- **Limits other issues associated with a three-year forward period**: In the case of PJM, there have been various other problems with the three-year forward period in RPM. For example, there has been concern about speculative bidding in BRAs, where resources are then able to buy out of capacity commitments obtained in the BRA at a profit in subsequent IAs. Separately, but relatedly, IA design and dynamics have been challenging, and IAs have systematically experienced prices that are not reflective of BRA outcomes and have, in fact, been much lower.
- **Better align price signals for unconventional resources**: Capacity resources that may be fastest to respond to price signals and system needs, like demand response ("DR"), may best be served by prompt auctions. These resources often struggle to subscribe customers years in advance but are well-situated to place offers in prompt auctions that more-accurately reflect the volume of capacity service they may offer at a range of price levels. The same can be said for distributed energy resource and distributed energy resource aggregators. Moreover, new resources like storage come online much more quickly than conventional resources, which means that capacity

19 Such circumstances occurred with the 2017 Tax Cuts and Jobs Act. While operator tax conditions changed considerably shortly after the passage of the legislation, the resulting changes will not be reflected in the net CONE parameter until the 2022/23 delivery period, likely imposing meaningful cost on ratepayers.

markets are contestable on timeline that is shorter than the lead time for a new natural gas unit.

Current investment dynamics may also warrant focusing alignment of capacity market price signals on supporting exit decisions. A significant amount of new entry in PJM, and across the US, is being driven by state policy decisions rather than purely by merchant economics. Economic development of merchant gas-fired capacity continues but may decline as environmental policy becomes more stringent. At the same time, coal and older gas capacity is steadily exiting the marketplace based on deteriorating resource economics. These dynamics further support the position that the most logical posture of RPM in the near- to mid-term is one that focuses on effectively managing resource exit.

Taken together, there appears to be little to recommend the current three-year forward period that is part of RPM. Prompt auctions allow new resources to develop long-term expectations (and/or sign long-term contracts) just as well as forward auctions, all while prompt auctions offer other benefits that provide better and more timely price signals to allow efficient resource decision-making. Such timeliness is likely to be particularly relevant as the power system changes in ways that may be more difficult to forecast three to four years in advance. As RPM evolves, evidence and logic suggest that the possibility of moving to a prompt structure be part of the conversation.[20]

Improve Transparency in Market Design and Participation

In considering potential changes to RPM, stakeholders would do well to consider how market transparency can improve to support how capacity sellers approach the market. Occasionally, this seems to be overlooked in discussions around RPM. Recent debates seem to revolve around whether prices are too high or too low. There is less focus on what kinds of rules and conditions support developers as they identify a long-term outlook for market outcomes. For example, rule stability is an important element to increasing investor confidence but has not been achieved in practice. As the discussion proceeds about the future of RPM, including various design changes large and small, this paper offers two suggestions, one general and one specific.

First, beware over-complexity. Any resource adequacy construct in PJM will inevitably be complex. However, while PJM’s stakeholders can collectively design theoretically efficient and intricate market designs, complexity can become a drawback. In particular, as described above, new entrants need to be able to develop long-term revenue outlooks. This frequently involves developing or hiring consultants to develop, forward price curves. Beyond a certain level of market complexity – for example, in market designs that include re-pricing or co-optimization across a number of products or attributes – such analysis

[20] From a practical perspective, yet another argument for a shorter forward period is that reduces the considerable delay between when market rule improvements can be made and when they are fully implemented. Likewise, more rapid rule implementation can eliminate the need for complex rules to manage confusing transition periods.

may become impractical. Additionally, increased complexity likely comes at the expense of transparency and understandability, design elements worth maintaining.

The second suggestion is to improve the availability of market data about the supply side. At this point, PJM offers scant insight into the makeup of the RPM supply curve. Following each auction, PJM issues sensitivity analyses which are informative, though limited.[21] PJM also publishes stylized representations of the supply curves from the auction, which are presented as smooth curves to mask ostensibly sensitive participant information.[22] Unfortunately, as PJM has acknowledged in the past, using statistical curve fit methods to represent unusually shaped curves can be unreliable, at best.[23] While it is unknowable at this time, given recognized challenges, there is a good chance that the curves that PJM currently provides are poor proxies for actual underlying supply curves based on seller offers.

Ideally, PJM could provide an anonymized supply curve, potentially with additional measures taken to mask individual participants or plants. Alternatively, PJM could revisit some of the reforms to the “curve fit” process considered when the Markets and Reliability Committee last took up the issue in 2014. If this were the case, published, smoothed curves should be accompanied by a goodness-of-fit measure, which would indicate to market watchers the quality of the curve fit.

Improving availability of data about RPM’s supply side would have several important benefits, primarily around improved ability of market participants to develop expectations. Having additional data on the shape of the supply curve would improve price forecasting efforts, which are key to long-term decision processes for capacity resources. There is currently little insight, particularly outside of the section of the supply curve immediately surrounding the clearing price and quantity. This means forecasters rely heavily on inference and generalization, updating imputed curve shapes following each revealed auction result.

This reactive forecasting cycle can be observed by comparing new entry with capacity auction prices in the same year and with prices in the prior year (i.e., one-year lag), as shown in Figure 2. Historical BRA data shows that there is no apparent correlation between prices and new entry in any given auction.[24] On the other hand, there is a clear positive correlation – with one explainable outlier – between high auction prices and new generation entry in the following auction. To a certain degree, this may not be surprising in

21 For example: https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2021-2022/2021-2022-bra-scenario-analysis.ashx

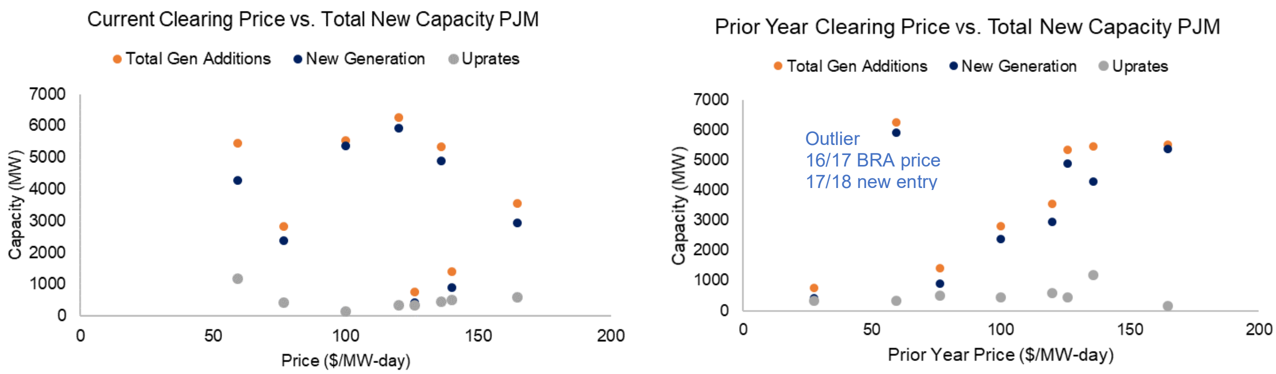
22 For example: https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2021-2022/2021-2022-bra-supply-curves.ashx

23 https://www.pjm.com/~/media/committees-groups/committees/mrc/20140529/20140529-item-11-rpm-supply-curve-transparency.ashx

24 This observation supports points made earlier in this paper related to the argument that new generation resources enter and clear the market in a same-auction response to high prices.

that a (high) price signal elicits the expected response of entry. At the highest level, that is the point.

Figure 2: Relationship between capacity prices and cleared generation additions versus prior year capacity prices and cleared generation additions[25]



Source: CRA analysis of PJM data

However, this observation begs the question as to why a single high price so reliably leads to a long-term change in expectation for future capacity revenues enough to drive investment in long-lived capital. One promising explanation may that that the high BRA price result biases capacity price forecasts upwards, in turn driving a short-term boost for new generation development regardless of whether a durable long-term increase in price expectation is really justified. Put another way, high prices may lead to unwarranted optimism if there is limited evidence to the contrary. If such outlooks are not justified, the result could be development of generation in excess of economic levels. A potential mitigant of this cycle would be to increase transparency about the supply curve, which could in turn limit the potential for overly bullish forecasting by allowing for more accurate representation of the supply side in capacity market modeling exercises. Providing more supply curve data may also provide consumers of price forecasts with more reason to be skeptical of aggressive price outlooks, thus moderating hasty entry decisions.

Revisit the Logic Underpinning RPM's Demand Curve Parameters

PJM is once again preparing for its quadrennial demand curve ("VRR") study, with the last one having been completed in 2018.[26] Though there are many moving parts, this timing may be fortunate in that it allows for the VRR curve to be revisited along with other changes being considered to the market design. One clear area for improvement is the

25 For BRAs 14/15-17/18, annual prices shown. For BRAs 18/19 onward, CP prices shown. What appears to be an "off-trend" data point in the one-year lagged chart is new resource cleared in the 17/18 BRA auction compared to the clearing prices for the 16/17 BRA. Following the 17/18 BRA, PJM noted that a majority of the new generation was in MAAC, which had previously experienced capacity price premiums and elevated resource clearing prices of ($120-170/MW-day), which, if graphed at the "break-out" prices, would move the data points right, consistent with the observed trend. The increase in generation additions in the 2017/2018 BRA may also have been a result of the fact that this was the first BRA following the 2014 polar vortex event, which may have given an impression of system tightness and fostered bullishness on the part of developers regarding future energy prices.

26 https://www.pjm.com/-/media/library/reports-notices/reliability-pricing-model/20180425-pjm-2018-variable-resource-requirement-curve-study.ashx

selection of the VRR curve's reference technology. For reasons not dissimilar to those supported by The Brattle Group following the last quadrennial assessment, this paper suggests that a CC better represents the technology that is expected to provide incremental, dispatchable contributions to resource adequacy in response to capacity price signals. While CCs may or may not be less expensive than combustion turbines ("CTs") on a net CONE basis, this should not necessarily be solely determinative of the selection of the reference technology used to set the VRR.

Instead of focusing on the technology cost of a specific unit type – or perhaps in addition – it is instructive that more than a decade of empirical evidence suggests CCs are preferred by developers. The majority of all new conventional capacity developed in PJM over the past decade has been CCs, amounting to approximately 26 GW of additions at 39 different sites. As Table 2 shows, this compares to only 1.5 GW of merchant CT capacity, with 20 units located at four plants. With the exception of LS Power's Doswell Peaking Plant (in VA), all of these generators were built in the high-priced EMAAC zone (MD, NJ). Notably, only the Doswell peaking units resemble the F-Class scale turbines (approximately 190 MW nameplate) used in the 2014 CONE study, and none of the merchant CTs in service today in the PJM footprint are of the scale of the H-Class turbines (approximately 320 MW nameplate) used in PJM's 2018 CONE Study. Rather, most of the CTs developed were in the 50-65 MW range in terms of rated generating capacity.[27]

Table 2: New gas-fired merchant generation in PJM (COD 2010-2020)

Technology	Nameplate GW	Units	Unique Sites
Combustion Turbine[28]	1.5	20	4
Combined Cycle	26	N/A	39

Source: CRA analysis of Energy Velocity data

There are likely several reasons for the prevalence of, and preference for, CC development over CTs. For one, it is possible that they are actually the most economical technology choice. Indeed, PJM's net CONE calculations suggest that, depending on geography, CCs may have a lower annualized net revenue requirement.[29] Practically, the forecasting required to estimate long term E&AS revenue streams is more straightforward and credible for CCs than CTs. Owing to considerable heat rate advantages, CCs run at higher capacity factors and are less subject to capacity factor and volume volatility on an annual basis than CTs. Larger volumes generated can mean larger swings in total margin expectations given broader market conditions, particularly gas price uncertainty, but generated revenues are always comfortingly high for investors. On the other hand, CT

27 The Bayonne turbines are Rolls Royce Trent 60 models. The turbines at Kearney – and at CP Crane, which is not listed here but under development – are GE LM6000 variants. Perryman uses a pair of Pratt & Whitney / Siemens FT4000. Doswell employs General Electric 7FA units.

28 For GTs included here, this analysis only includes merchant plants developed with the primary purpose of selling to the wholesale market. Excluded are plants collocated with industrial loads, backup generators (e.g., at hospitals), regulated plants, and combined heat and power facilities. What remains are the plants that would generally be expected to resemble the current reference unit and are of the type that might be responding to merchant price signals.

29 https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2022-2023/2022-2023-default-mopr-floor-offer-prices-for-certain-new-generation-that-is-not-state-subsidized.ashx

operations are significantly driven by infrequent and unpredictable high price periods. These can be hard to model with traditional deterministic approaches, and when modeled can show long periods of compressed revenues *and* margins interspersed with short, high-value opportunities, all spread across limited volumes. Such operational expectations can be a daunting prospect for potential investors.

This is not an argument for chasing the lowest cost generating technology. As suggested in the 2018 quadrennial review, CCs represent the technology most likely to fulfill a marginal demand for capacity to achieve resource adequacy, both based on spreadsheet exercises and from empirical observation. Furthermore, while the immediate effect of lowering net CONE, all else equal, is to reduce capacity prices, this is not an argument aimed at lowering prices, nor one that necessarily would over the long term. In fact, it is conceivable that lowering the height of the demand curve could increase prices in the long run, or at least stabilize them. The capacity market is currently considerably oversupplied. In part, this is likely due to overly bullish outlooks produced by some capacity price forecasting methodologies, and acted upon by developers, that are partially facilitated by the height of the VRR demand curve, which is based on a net CONE estimate that is likely inflated. Reducing the VRR curve's height could temper such expectations, thus deterring the type of investment that has led PJM to realize reserve margins consistently in excess of 25% and leading to margins closer to those targeted in the demand curve design process, with the accompanying higher prices.[30]

While changing the reference unit to a CC may be warranted in the near term, the PJM system may also be approaching a point that, for regulatory and/or economic reasons, there may be limited development of new gas capacity. Storage resources, or storage paired with renewables, could become the favored dispatchable technology to respond to incremental capacity demand. As the potential for this transition approaches, so too should the associated RPM parameters. Though we may not reach this point in the near term, PJM and its stakeholders should prepare for this eventuality and have in place reference unit selection criteria that accommodate the shift when it is indicated.

In addition to reconsidering the administrative net CONE estimate and the resource type it is based upon, it may be worth considering a VRR curve shape with an emphasis on alignment with the value of the product being procured. That is, the current shape represents a compromise solution designed to accomplish a range of objectives – including mitigating market power and price volatility, driving different levels of price elasticity at different reserve margin levels, and the core objective of procuring sufficient

30 It is questionable whether capacity market outcomes should be expected to settle around net CONE on average. While this is potentially a necessary design criterion when performing a demand curve study, empirical evidence again indicates against such expectations in the long term. Historically, US capacity markets have consistently achieved reserve margins well in excess of targets at prices averaging 30-50% of net CONE. This may be attributed to a range of factors, likely including poor participant (and designer) foresight and forecasting optimism, over-conservative (high) parameters in establishing net CONE values, and overbuilding as a result of lack of coordination. Perhaps, in the absence of these factors, net CONE pricing levels would prevail, but that is likely a non-testable hypothesis.

resources to maintain resource adequacy.[31] An alternative, like ISO-NE's marginal reliability impact ("MRI") curve may be more principled – aligning demand represented by the VRR with the reliability value of increasing reserve margins – and may potentially reduce the likelihood of significant over-procurement by more quickly limiting available capacity revenue when capacity supply is abundant. There may also be a need to reconsider the structure of the quadrennial VRR review methodology with an eye towards why the resulting VRR curves have systematically led to such high reserve margins.[32]

This is not, however, to imply that pursuing minimum acceptable procurement levels is or should be the objective. Recent extreme weather events have demonstrated that carrying thin reserve margins has accompanying risk, and incremental capacity can have considerable value. However, there is a balance to be struck between ensuring sufficient reliability and maintaining higher levels of reliability than are cost effective.

Seller Market Power: A Manageable Concern

Concern over the presence and exercise of seller market power is a persistent topic in PJM and FERC discussions about RPM, particularly as it relates to any alternative market designs or design revisions. Awareness of supply-side market power is a legitimate concern, but it is addressable and should not be a deterrent to rule changes that would otherwise improve the capacity market.

In terms of the presence of supply-side market power, such conditions are likely endemic in any capacity market, including PJM's. By their nature, capacity markets should be relatively tight, with the vast majority of generators taking on capacity obligations and limited uncommitted capacity.[33] Indeed, it would likely be inefficient to have generating capability considerably in excess of what is required to achieve resource adequacy. This reality naturally leads to the presence of pivotal suppliers, without whom the market could not clear and that will likely have the ability and incentive to raise prices above competitive levels.

Having acknowledged the likelihood of seller market power, this paper suggests that any capacity market design should include a reasoned and thorough *ex ante* market power mitigation scheme. Particular conservativism is also warranted in any capacity market mitigation design. By comparison, in an energy market, outcomes are transient, and the effects of anti-competitive behavior often expire after one or several five-minute settlement intervals. The total cost stakes in the energy market are relatively small in any given hour. Furthermore, uncompetitive behavior can often be observed and addressed on a more

31 See, for example, The Third Triennial Review of PJM's Variable Resource Requirement Curve, pgs. 45-51. (https://brattlefiles.blob.core.windows.net/files/7510_third_triennial_review_of_pjm's_variable_resource_requirement_curve.pdf)

32 For example, the way that the Monte Carlo modeling approach introduces probabilistic shocks on both the supply and demand side of the modeling analysis appears to produce aggregate results that are not well supported by historical observations.

33 Whether or not they are realistic, design studies expect cycling periods of over- and under-supply, with average supply around equilibrium (assumed to be at or around net CONE pricing levels) through time.

expedient basis before the overall effects accumulate to become large costs to consumers. In a capacity market, on the other hand, outcomes persist for long periods; capacity commitment periods are a full year. In RPM, achieving a price difference of $1/MW-day could drive as much as $60M in additional consumer costs,[34] so it is easy to see how certain offer behavior and overly-permissive offer rules could drive uneconomic costs to customers on the order of hundreds of millions of dollars.

While a serious concern, such market power is not to be feared. Rather, it is to be managed and mitigated. Screens, like those currently in place in PJM and other markets, can identify those entities that may possess market power.[35] Maximum offer thresholds may then be set to constrain the offers of screened market participants, such that offers above a pre-set level of concern must be justified. Corresponding procedures should be in place so that such resource-specific reviews and exemptions can be adjudicated fairly, consistently, and transparently by the RTO and/or market monitor, with recourse to FERC if agreement cannot be reached.

Opposition to conservative supply-side market monitoring and mitigation rules will cite concerns about administrative cost and the specter of "over-mitigation." To the first count, while the cost of resource-specific reviews for supply-side mitigation is non-zero, it is certainly orders of magnitude less than the potential cost impact of letting the exercise of market power go unchecked.[36] Furthermore, over-mitigation occurs when resources are compelled to offer below their true costs, thus putting them into position in which they may be forced to provide a product at a financial loss. If the rules for resource-specific offer cap exemptions and reviews are established to be fair and effective, over-mitigation should not be a worry. Acknowledging criticisms about how the IMM adjudicates resource-specific reviews, this is admittedly a very large 'if.'[37] However, as long as the resource-specific offer reviews allow sellers to justify and submit offers at their avoidable going forward cost that reflect any risks associated with taking on a capacity obligation, over-mitigation can be fully addressed. If concern lingers, then attention is perhaps better directed at how resource-specific reviews are adjudicated, and it is those processes that need reform.

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34 Roughly 160 GW of UCAP procured, times $1/MW-day, times 365 days in a delivery year.

35 This is not an endorsement of PJM's three-pivotal supplier methodology. Rather, this is just to note that it is a screen designed with the intent discussed.

36 There are a number of promising proposals that have been put forth related to revisions to the Market Seller Offer Cap that could constrain the administrative burden of offer review. This could be achieved by focusing offer review closely on only those resources intending to offer at a level at which they would have a meaningful impact on market clearing prices. For example, several intervenors in Docket No. EL19-47, EL19-63 suggest approaches for limiting review to those market participants that wish to offer around or in excess of recent market clearing prices. An alternative approach to arriving at a similar result would be for PJM to shift to a conduct and impact mitigation methodology, rather than continuing to use a structural approach.

37 Generator owners are relatively uniform in their agreement that the IMM's resource-specific review process – as it has been experienced as part of both sell-side and MOPR mitigation processes – is broken. There are concerns with the pace, process, flexibility, transparency, consistency, and recourse available within the process. There seem to be particular challenges associated with accommodating non-conventional resource structures, and with how risk is allowed to be reflected in offers (as raised in Docket No. EL19-47 and EL19-63, as well as EL21-10). These are worrying allegations. Thus, this paper does not assert that there are no problems with the unit-specific review process as it stands. Rather, it suggests that, if that process is the problem, then it is that process that should be fixed. The solution should not be to take an overly permissive stance towards the mitigation of market power.

Taken together, seller market power in capacity markets is to be expected, is a serious issue, and is addressable. Given the high costs of being overly permissive, a conservative approach to managing such market power is warranted and should include a robust process for resource-specific reviews for offers above any default mitigation thresholds. Having established such rules with reasonable recourse, further allusions to over-mitigation should be viewed as the red herring they are. Above all, however, unavoidable concerns about seller market power should not stand in the way of needed reforms. Instead, they can and should be addressed in the course of implementing capacity market design changes.

Continue Efforts to Better Define the Product and the Value of Capacity

As the PJM system evolves, it will be important to ensure that capacity balance is maintained in a manner that recognizes resource contributions and demand patterns. To this end, on the supply side, PJM's effective load carrying capacity ("ELCC") reforms appear to be a move in the right direction. Proposed for implementation as early as the 2023/2024 BRA, the under-development ELCC rules establish new structures for qualifying intermittent, storage, and hybrid resources.[38] While early indications are moderately negative for wind and solar resources in terms of current UCAP derating factors, employing an ELCC approach promises to more rigorously align resource adequacy contributions to capacity qualification rules. Furthermore, PJM's current proposal is beneficial to storage resources, particularly when compared to the punitive capacity derating factors previously proposed, and creates a structure for hybrid (or "combination") resource participation, a feature that is currently lacking.

There may also be room to improve the matching of supply and demand via changes to the granularity of RPM procurement. As with most power systems, both the demands of the system and the available system supply change substantially from one season to the next. Not only are such patterns more pronounced with increasing penetration of renewable resources, changing degrees of electrification may also drive departures from the current status quo, with some regions in the US expecting shifts from being summer to winter peaking. Thus, there may be merit to procuring and valuing capacity on a basis that is more closely aligned with its delivery. To this end, procuring capacity on a seasonal basis is worth considering, with the following potential benefits:

- Better align capacity resource availability and the system's seasonal capacity needs with capacity procurement and prices;
- Potential to achieve savings by allowing relatively high-cost resources to take seasonal outages during low-price periods;

38 FERC Docket No. ER21-278. PJM's proposal was rejected by the Commission on April 30, 2021 over the nature of an included "transition mechanism," but it seems likely that PJM will shortly have approved a similar rule change.

- Increase flexibility by allowing resources to come online or retire mid-year without having to procure significant replacement capacity for pre-online or post-retirement obligations; and
- Align qualification and compensation of resources with extended outages to their availability.

Getting Pointed in the Right Direction

The purpose of capacity markets is to provide a supplemental revenue stream—in addition to revenues available from energy and ancillary service markets—that can serve as a *reasonably predictable*, *long-term* mechanism to support efficient entry and exit of supply. Particularly for new entrants, investors and developers should, and do, look to capacity revenue expectations as a key supporting factor to evaluate resource economics. In building the business case for merchant investments that frequently run into the hundreds of millions of dollars, the more certainty around market rules and structure that can be afforded by the market operator and its regulator, the better. Moreover, it is critical not to lose sight of the role that capacity markets play in facilitating efficient and timely exit, the implications of which seem to be often overlooked in discussions about RPM and are lacking in the current market design.

With luck, PJM and FERC will make progress towards improving certainty as the controversy around the expanded MOPR is put in the past. For the sake of long-term system reliability and cost-effective provision of resource adequacy, the coming years will hopefully see a steadier grounding for RPM. While continued tinkering with market rules can run counter to this objective, this paper suggests some areas of improvement, including several targeted, principled reforms, that could better position RPM to continue to support cost effective achievement of resource adequacy in the face of a rapidly changing supply mix.

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About the Author

Jordan Kwok (jkwok@crai.com, 202-662-3811) is a Principal with the Energy Practice of CRA. He has worked with regulated utilities and merchant operators throughout the United States with a focus on regulatory strategy, ISO/RTO market policy, and project valuation. Jordan was formerly an Energy Industry Analyst in the FERC's Office of Energy Policy and Innovation. Prior to joining CRA, Jordan managed the State Department's Power Sector Program, a technical assistance program supporting power sector reform in developing countries by fostering solvency, competition, sustainability, and access. Mr. Kwok has an MS in Technology and Policy from MIT and a BS in Materials Science and Engineering from Northwestern University.

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