The Fixed Resource Requirement Alternative to PJM's Capacity Market

A Guide for State Decision-Making

State Energy & Environmental Impact Center at the NYU School of Law

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AUTHORS

Max Chang
Jason Frost
Courtney Lane
Steve Letendre, PhD

Synapse Energy Economics, Inc.

485 Massachusetts Avenue, Suite 3
Cambridge, Massachusetts 02139

617.661.3248 | www.synapse-energy.com

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SUMMARY

The Federal Energy Regulatory Commission's (FERC) December 19, 2019 Minimum Offer Price Rule (MOPR) order[1] directed PJM Interconnection Inc. (PJM), to make substantial changes to the way PJM operates its wholesale capacity market.[2] Specifically, FERC directed PJM to expand the application of MOPR to all "state-subsidized" resources.[3] Although existing renewable energy resources are exempt, the order applies to new renewable energy projects receiving a state subsidy that seek to participate in PJM's capacity market and do not yet have an interconnection construction service agreement[4]with PJM. The order also applies to all existing nuclear units. See Appendix A for a full discussion of PJM's capacity market and the FERC's December 19, 2019 MOPR order.

Many stakeholders have expressed concern that new renewable resources subject to high offer floors will not clear PJM's capacity auctions[5] and thus not receive capacity revenues. Indeed, analysis by PJM's Independent Market Monitor (IMM) found that initial estimates of offer floor prices applicable to several types of new renewable resources would not allow these resources to clear PJM's capacity auctions based on recent market-clearing prices. The loss of capacity market revenues will likely increase the cost to meet state clean energy goals through increases in the prices for renewable energy credits (REC). Furthermore, if the capacity provided by renewable energy resources is not counted towards PJM's resource requirements, ratepayers will potentially pay twice for capacity.

The Fixed Resource Requirement (FRR) is an existing mechanism available to utilities and load-serving entities (LSE) as an alternative to continued participation in PJM's capacity market. The FRR alternative requires a utility or LSE to develop a plan to procure enough capacity to meet the forecasted peak demand for power for all customers within the designated FRR zone.[6] States within PJM's footprint may be considering whether the FRR represents a viable alternative that allows greater control over the

[1] The Federal Energy Regulatory Commission's December 19, 2019 Minimum Offer Price Rule (MOPR) Order Docket Nos. EL16-49-000 and EL18-178-000 (Consolidated) is available at https://www.ferc.gov/whats-new/comm-meet/2019/121919/E-1.pdf.

[2] PJM is the regional transmission organization (RTO) for 13 eastern and midwestern states and the District of Columbia. The PJM capacity market is known as the Reliability Pricing Model (RPM) and functions with the goal of ensuring there are sufficient resources to meet future demand needs across PJM.

[3] FERC's April 16, 2020 Rehearing Order addresses additional questions from the December 19th order. The Rehearing Order is available at https://www.ferc.gov/whats-new/comm-meet/2020/041620/E-5.pdf.

[4] An interconnection construction service agreement is a contract to connect a generator to a point on the transmission system located within PJM's footprint.

[5] A resource would fail to clear the capacity auction when its default floor offer price is higher than the market-clearing price for that auction.

[6] An FRR zone can be defined as the service territory for an investor-owned utility, public power authority, or electric cooperative. In addition, an FRR zone can be a separately identifiable geographic area that is bounded by wholesale metering for which the FRR entity has or assumes the obligation to provide capacity for all load (including expected growth) within such area.

resources that are procured and built to meet both consumer energy needs and their clean energy policy goals.[7] At this time, there is much uncertainty around the costs and benefits of FRR relative to continued participation in PJM's capacity market. Furthermore, there is uncertainty about the regulatory and legislative changes needed to facilitate utilities' and LSEs' pursuit of the FRR alternative.

This guide presents a three-step framework that states can use to evaluate the FRR alternative. Specifically, this guide can be used by states to assess the economic and financial trade-offs between the FRR alternative and continued participation in PJM's capacity market. This guide also highlights state regulatory and legislative actions that may facilitate the adoption of the FRR alternative.

[7] Several states are considering exiting PJM's capacity market over concerns about the impact of FERC's MOPR order on state clean energy goals. As one example, the New Jersey Department of Public Utilities announced on March 27, 2020 plans to investigate alternatives to the state's continued participation in PJM's capacity market (see, https://www.bpu.state.nj.us/bpu/pdf/MOPR%20Press%20Release%20327_FINAL.pdf).

OVERVIEW OF THE FRAMEWORK

The framework seeks to assist states in deciding whether to proceed with an FRR alternative and the legislative and regulatory actions that may be required to implement the FRR alternative.

As shown in Table 1, the PJM territory differs with regards to electric restructuring,[8] renewable portfolio standard (RPS) mandates,[9] and experience with the FRR alternative. Each of these factors will influence a state's path to an FRR alternative and its decision-making process. Even across states with restructured electricity markets and RPS requirements, each will have its own unique laws and regulations. For these reasons, the framework is intended as a planning tool to guide states in their decision-making processes and is not intended to be a state-specific guide.

Table 1. Summary of PJM States

PJM State	Restructured Electric Market	Renewable Portfolio Standard	Current FRR
Delaware	✓	✓	
Illinois	✓	✓	
Indiana		Voluntary	✓
Kentucky			✓
Maryland	✓	✓	
Michigan	✓	✓	✓
New Jersey	✓	✓	
North Carolina		✓	
Ohio	✓	✓	
Pennsylvania	✓	✓	
Tennessee			
Virginia	✓*	✓	✓
West Virginia			✓
District of Columbia	✓	✓	

**Virginia excludes residential customers. RPS mandate recently was enacted.*

[8] Electric restructuring relates to states that have deregulated their electricity market so that the electric utilities are no longer allowed to own generation. Utilities in these states only own distribution assets and customers in these states can choose to shop for electricity supply from competitive retail suppliers or remain with their distribution utility to receive supply through standard offer service (also often referred to as basic service or default service).

[9] RPS mandates require utility companies and other retail electric providers to supply a specified minimum percentage (or absolute amount) of customer demand with eligible renewable resources. This is often done by turning over a corresponding number of RECs to the state utility commission.

The framework recommends that any state contemplating an FRR alternative work through three key steps:

Step 1. Identification of issues

- Prior to conducting any analysis, a state should identify the issues it wants to solve by implementing the FRR. For example, is a state seeking to provide capacity revenue for new renewable energy resources in order to promote state clean energy goals or is it looking to take more control over capacity procurement to ensure greater price stability? Identifying the issue or issues a state seeks to address will set the foundation for what type of economic and financial analysis would be required and for which related legislative and regulatory questions need answers.

Step 2. Economic and Financial Analysis

- States should consider the full set of potential financial and economic implications of adopting the FRR. This evaluation should encompass benefits including reduction in clean energy incentive costs (discussed below) as well as costs such as the exercise of market power in smaller FRR capacity procurements. These costs and benefits will vary by state and utility service territory, but the framework described here can serve as a template for cost-benefit analysis of the FRR alternative across the PJM footprint. Economic implications are important to consider given the size of the PJM capacity market and the potential of the FRR alternative to lock in higher or lower capacity payments for the minimum five-year period required by the FRR.

Step 3. Assessment of Legislative and Regulatory Actions

- After conducting the needed economic and financial analysis, the last step is to assess changes needed to existing state laws and regulations to enable the FRR. This step will be different for states that have undergone electric restructuring than for those with regulated markets. For example, restructured states may need to amend laws governing retail competition and regulations regarding the procurement of standard offer or default service. These considerations will also impact the timing of pursuing an FRR plan. Regulated states may only need legislation that requires utilities to implement FRRs.

After a state works through these three steps, it should be able to assess whether to proceed with an FRR alternative to address concerns with FERC's December 2019 MOPR Order and the March 18, 2020 PJM Compliance filing.[10]

[10] At the time of this publication, FERC rejected rehearing requests from states but had not yet ruled on PJM's March 18, 2020 compliance filing. Numerous stakeholders have also filed petitions for review before various U.S. Courts of Appeals challenging the Order.

STEP 1: ISSUE IDENTIFICATION

The first step a state should take in deciding whether to pursue an FRR alternative is identifying the problems it hopes to solve.

A number of state petitions for rehearing and clarification to the FERC MOPR order identified several issues, including:

- Inability of new renewable energy resources to clear the market, therefore impeding a state's ability to achieve clean energy and carbon reduction goals;
- Paying twice for capacity—once for resources clearing the PJM capacity auction and a second time for renewable energy capacity that does not clear the capacity auction but is required to meet RPS goals; and
- Creation of bias towards fossil-fuel based generation, which could limit competition and potentially increase capacity costs.

The key problems a state seeks to solve will determine the type of analysis needed. Below are examples of several FRR goals and relevant assessment questions.

Example goal	Sample questions to answer
Example: FRR goal is to provide capacity revenue for new renewable energy	**Sample questions to answer:** • Can a state achieve its long-term clean energy and environmental objectives within the existing PJM capacity market construct through other means (e.g., higher REC prices or power-purchase agreement floor prices)? • Would an FRR provide the needed capacity payments to renewable energy resources? For example, how many megawatts (MW) of new RPS resources would be eligible for inclusion in an FRR based on limiting factors such as the Minimum Internal Resource Requirement (MIRR) dicussed below?
Example: FRR goal is to avoid paying for unneeded capacity	**Sample questions to answer:** • Will the state need to continue paying to support the development of new renewable capacity in addition to the capacity in the FRR? • Will the state be overprocuring capacity if it is locked into a 5-year FRR and load is reduced due to distributed energy resources?
Example: FRR goal is to mitigate potential price increases to ratepayers	**Sample questions to answer:** • Who owns the generation in the proposed FRR? Will there be sufficient competition, or would one or more entities have market power? • How will the FRR impact current and future energy efficiency and demand response programs? • What are the administrative costs and risks associated with the FRR? • How will the FRR impact retail electric competition in restructured states?

Understanding these key issues and questions will guide which of the economic and financial analyses described in Step 2 are needed.

STEP 2: ECONOMIC AND FINANCIAL ANALYSIS FRAMEWORK

Capacity payments represent a substantial portion of consumer electricity costs. For the 2019/2020 Delivery Year, the total cost to customers of PJM's RPM was $7 billion.[11] The expanded MOPR may cause capacity costs for future delivery years to be even higher.[12] As the PJM RPM is such a large market (163,000 MW), the costs and benefits of exiting the capacity market should be rigorously examined before choosing the FRR alternative. The requirement that a state that chooses the FRR alternative must remain in the FRR for at least five years also increases the stakes of this decision. An FRR LSE will be stuck with the costs for the full 5-year period whether or not these costs ultimately outweigh the benefits of selecting the FRR alternative.

Exiting the PJM capacity market and choosing the FRR alternative can have large financial implications, both positive and negative, in addition to impacts on state environmental goals. The precise set of impacts will vary among states and utility service territories. In some cases, some of the costs and benefits described below will not apply. In others, all of these impacts may be relevant to the decision. To comprehensively evaluate the FRR alternative, states should quantify the impacts described in this section as rigorously as feasible so that stakeholders can make informed decisions about whether or not to pursue the FRR alternative instead of continued participation in PJM's capacity market.

Benefits of the FRR Alternative

As described in Step 1, states may consider the FRR alternative to avoid double-paying for capacity by acquiring both RPM-cleared capacity and new renewable capacity. Avoidance of paying twice for capacity could result in substantial savings under the FRR and is one of the primary short-term financial benefits to consider. An FRR can also help states meet their clean energy targets. In states that place caps on renewable incentives (such as REC prices), the MOPR could prevent the development of some new renewable capacity that would be needed for meeting state goals. Capped incentives for renewables may not be high enough to fully cover lost capacity payments for new resources that fail to clear the capacity auction because of the expanded MOPR. As a result, these states may struggle to meet renewable targets. An FRR can direct capacity revenue to new renewables, relieve pressure on incentive prices, and increase the amount of renewable capacity beyond what would be developed

[11] Monitoring Analytics, LLC. March 12, 2020. *2019 State of the Market Report for PJM, Volume 2: Detailed Analysis*, page 254. Available at: https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2019/2019-som-pjm-sec5.pdf.

[12] A study by ICF found that capacity prices in PJM's capacity market could increase by 25 – 30 percent assuming no states pursued the FRR alternative. See https://www.spglobal.com/platts/en/market-insights/latest-news/coal/020620-mopr-could-cause-pjm-capacity-market-pricing-collapse-study

under the expanded MOPR. A third economic impact of adopting the FRR alternative is the potential reduction of capacity prices within an FRR zone. In theory, new renewable resources would compete to provide capacity that would put downward pressure on overall capacity prices for the FRR zone.

Reduced Cost of State Clean Energy Programs

The primary financial benefit of the FRR alternative is to avoid paying twice for capacity. If the capacity from new renewable resources receiving state incentives is not counted toward PJM's capacity requirement, then consumers may end up paying twice for capacity: once for unnecessary fossil generation through the RPM and once in the form of higher incentive costs for renewable resources needed to meet state clean energy goals.

Under the MOPR, new renewable capacity (onshore and offshore wind in particular, based on PJM's proposed net CONE values) is unlikely to clear the capacity market. However, state policies such as an RPS require an increasing fraction of electricity to be purchased from renewable resources. For these policy targets to be met, new renewable resources will still need to be developed, whether they are permitted to clear in the capacity market or not. The total cost of these resources is unlikely to change depending on whether their revenue comes from capacity payments or state incentives. Therefore, state clean energy incentive costs would likely increase under the MOPR to offset lost capacity revenue and bring new renewable resources online. In practice, this is most likely to be reflected in higher REC prices, which will be passed on through customer electricity bills. In states that are procuring offshore wind or other specific renewable resources, procurement costs would also increase under the MOPR if these resources can no longer receive PJM capacity revenues.

By diverting capacity revenue from future renewable resources to existing fossil fuel power plants that are no longer needed, the expanded MOPR forces states that have clean energy targets to effectively pay twice for capacity. States have made the choice to purchase clean energy capacity regardless of PJM market rules. The expanded MOPR would burden consumers with duplicative capacity payments to fossil fuel power plants that are not needed to meet the actual capacity needs of the grid given the renewable resources that states are bringing online to meet their clean energy goals.

The FRR alternative could allow states to avoid double-paying for capacity by providing capacity revenue to renewable resources instead of to fossil fuel generators that may clear at lower prices in the auction because of the expanded MOPR. With the capacity revenue, new renewable projects could be financed with lower incentive payments, resulting in savings for consumers. By allowing new renewable resources to count toward capacity requirements, the FRR alternative could avoid the need for consumers to purchase excess and duplicative capacity from unnecessary fossil fuel power plants.

Achievement of Clean Energy Targets within Existing Incentive Cost Caps

Some states have cost caps that limit the total cost impact of their clean energy programs on consumers. In these circumstances, the MOPR may result in a need for incentives beyond the cap value to incentivize the required amount of renewable generation capacity. Cost caps (sometimes referred to as Alternative Compliance Payments, or ACPs)[13] can limit the cost impact of the MOPR described in the preceding section by limiting the incentive costs that consumers pay as part of an RPS or other renewable program. However, if the caps are too low they could potentially reduce the amount of renewable capacity that comes online as the available revenues for renewable generators would be insufficient to incentivize new renewable capacity.

This means that the MOPR increases the risk that states will fail to meet their clean energy goals. In the case of RPS policies specifically, the MOPR increases the risk that utilities or LSEs will pay ACPs instead of purchasing the required number of RECs. Under the FRR, states can direct capacity payments toward new renewable resources, thereby increasing the amount of renewable capacity that can be financed under existing cost caps and reducing the risk that states fail to meet clean energy targets.

Lower Capacity Prices Due to Inclusion of New Renewable Resources in Procurements

Allowing new renewable resources to fully participate in the capacity market would tend to reduce capacity costs for all consumers, as they would displace resources with higher capacity offer prices. While there are other factors that could lead to higher FRR capacity procurement prices discussed below, allowing full competition from new renewable resources would tend to decrease the capacity costs consumers would pay under an FRR relative to the RPM under MOPR.

Costs of the FRR Alternative

The potential for elevated costs in the FRR alternative is mostly due to the impacts of market power and reduced competition. There are two main ways that this can happen. First, the LSE or utility FRR procurement would be smaller than the PJM capacity market and may attract fewer offer bids. If the FRR were competitively bid, this could lead to larger steps from one price to a higher price in the supply curve and clearing prices could rise if lower priced units choose to participate. Second, some FRR regions would have MIRRs[14] that require capacity to be procured from within locational deliverability areas (LDAs). In some LDAs, there are only a handful of generation resources and their ownership is concentrated among one or two entities. This creates opportunities for exercising unmitigated market power and could raise capacity prices for consumers in FRR regions that have significant MIRRs requirements. In addition to these two market power issues, a third potential source of costs related to selecting the FRR alternative are administrative and regulatory costs that result from utilities and states taking on roles for which PJM is currently responsible in the RPM.

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[13] An Alternative Compliance Payment or ACP is the penalty that a utility pays for not acquiring and retiring one REC, as required by an RPS. The ACP effectively caps the price of a REC, because a utility would prefer to pay the ACP rather than purchase a REC at a price above the ACP.

[14] A Minimum Internal Resource Requirement, or MIRR, is a requirement under the FRR that a fraction of the procured capacity comes from within a local geographic region called an LDA. MIRRs are based on specific transmission limits between the LDA and the rest of PJM.

Reduced Competition Due to Smaller Procurement Size

For procurements held in relatively small FRR zones, fewer resources may choose to participate and offer their capacity. This would lead to a supply curve with fewer resources overall and therefore larger jumps in price between adjacent resources in the supply stack. Depending on the auction or procurement structure, a smoother supply curve with smaller price jumps would tend to create more optimal price outcomes. The smaller number of resources likely to participate in an FRR procurement process could increase capacity prices within an FRR zone relative to the RPM.

Market Power Due to Ownership Concentration

For some utility service territories, transmission constraints will necessitate a portion of capacity—enough to satisfy the MIRR—coming from within the service territory or the surrounding area. Within these smaller footprints, ownership of generation resources can be concentrated among one or two entities. This would lead to market power for such entities under an FRR. While these entities already have some market power within the PJM capacity market (which also faces transmission constraints in some zones), PJM employs market power mitigation measures to address the issue. These measures would no longer be enforced in an FRR. For this reason, concentrated ownership can create a greater risk to the competitive process under the FRR alternative than under the RPM, unless market power is effectively mitigated by a state authority (discussed below).

Administrative Costs Involved in the Procurement Process

Market mitigation is just one of the new responsibilities that would fall to states, utilities, and LSEs under the FRR alternative. Numerous functions carried out by PJM within the capacity market would need to be replaced by administrative and regulatory actions performed by states, utilities, and LSEs. For example, administrative costs faced by the LSE could include those associated with the qualification of new resources and with conducting a capacity procurement process or auction. Determining how to operate the procurement process would also take time and effort.

Other administrative costs and responsibilities would fall on regulators. These costs could include public utility commission efforts to monitor and mitigate non-competitive behavior as well as commission review and approval of capacity procurements. Procurement results can either be monitored on a case-by-case basis, or regulators could adopt market mitigation strategies similar to those employed by PJM and other RTOs. One such strategy would be restrictions on capacity offer prices. The potential need to develop these additional mechanisms to successfully develop and deploy an FRR alternative should be considered as part of an evaluation of the FRR alternative.

STEP 3: ASSESSMENT OF LEGISLATIVE AND REGULATORY ACTIONS

The FRR alternative is an option for both regulated and restructured states, including both investor-owned and publicly owned utilities. However, the path to implementing an FRR alternative in a state with a competitive, restructured electricity market is far more complex and likely requires changes to laws and regulations, as well as considerations of impacts on competitive retail electricity providers.

States with regulated electricity markets have a more direct path to an FRR alternative, with vertically integrated utilities already self-supplying[15] generation capacity for the entire service territory. For this reason, the two current FRRs in PJM are in mostly regulated states.[16] The first is the American Electric Power FRR Plan covering portions of Virginia, West Virginia, Indiana, and Michigan. The second is Duke Energy serving Kentucky.

This section examines the differences for states with electric restructuring and states with regulated electricity markets in implementing an FRR.

States with Electric Restructuring

Restructured states have deregulated their electricity markets so that utilities are no longer allowed to own generation. The utilities, often referred to as electric distribution companies, only own distribution assets. Customers in these states can choose to shop for electricity supply from competitive retail suppliers or can remain with their distribution utility to receive supply through standard offer service (SOS), also referred to as default service or basic service.[17]

Several factors unique to these states make it more difficult for the states to require utilities to implement an FRR alternative:

- The amount and type of new generation is primarily determined by wholesale market forces, and resource planning is largely removed from the public utility commission and the state in general. Commissions may not have the required authority to oversee FRR plans, and statutes and regulations may need to be amended. By enacting restructuring, many states relinquished their ability to review cost of service, which would be required to assess the prudency of capacity costs in an FRR Plan.

[15] Self-supply is when a utility uses its own generation resource to meet the electricity needs of its customers.

[16] While Michigan and Virginia have passed electric restructuring laws, there are nuances that make these states better able to implement the FRR alternative. Michigan maintained rate regulation and service mandates for the incumbent utilities, placed a cap on how much of a utility's retail load is eligible to pursue retail choice at 10 percent of total load, and requires utilities to maintain enough capacity at all times to serve peak demand of all customers in their territory (similar to the FRR requirement). Similarly, Virginia only has retail competition for non-residential customers.

[17] We note that FERC's April 16, 2020 Rehearing Order categorizes all default service auctions as a state subsidy and therefore subject to the MOPR. See Paragraph 386.

- Electric distribution companies and competitive retail suppliers are both procuring bundled energy and capacity from the wholesale market to meet customer demand. The FRR would require the distribution company to procure capacity for its customers and the customers of any retail supplier.[18]

- Most large commercial and industrial customers are buying electricity supply from competitive suppliers, while a majority of residential customers receive default service from their electric distribution company.

- The contracts for SOS procurement generally have durations of three years or less, but the FRR alternative requires planning in at least 5-year cycles.

States will need to address each factor by considering changes needed to accommodate the FRR alternative, including to existing laws and regulations, timing and length of capacity procurement, and oversight of capacity procurement. They will also need to consider impacts to retail competition.

Existing Laws and Regulations

States with restructured electricity markets will likely need to amend existing laws and regulations if they want to pursue the FRR option. The list below provides examples of possible actions needed.

1. Establishing authority: Leaving the PJM capacity market will require states to adopt legislation directing regulated distribution utilities to implement the FRR option.[19] Legislation may also be needed to provide sufficient authority to state regulators or agencies to administer and oversee an FRR.

2. Amending electric restructuring laws and regulations: Such laws and regulations describe the process for how electric distribution companies should procure energy and capacity to meet customer needs (See MD Code §7-510 as an example). The FRR would require the distribution company to procure capacity for its customers and the customers of any retail supplier.[20] Therefore, a rulemaking or statutory amendment may be needed to clarify that any distribution company entering into an FRR would be permitted to procure capacity for both its load requirements and that of any competitive

MD Code §7-510 "competitive process shall include a series of competitive wholesale bids in which the investor-owned electric company solicits bids to supply anticipated standard offer service load for residential and small commercial customers as part of a portfolio of blended wholesale supply contracts of short, medium, or long term."

[18] Section D.8 of Schedule 8.1 of the PJM Reliability Assurance Agreement states, "In a state regulatory jurisdiction that has implemented retail choice, the FRR Entity 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 retail LSEs. In the case of load reflected in the FRR Capacity Plan that switches to an alternative LSE, where the state regulatory jurisdiction requires switching customers or the LSE to compensate the FRR Entity for its FRR capacity obligations, such state compensation mechanism will prevail."

[19] *See, e.g.*, PJM Compliance Filing on FERC's MOPR Order at page 86. Available at: https://www.pjm.com/directory/etariff/FercDockets/4443/20200318-er18-1314-003.pdf.

[20] A state could choose to have a designated agency conduct a competitive procurement process for a FRR capacity requirements. In this case, costs could be recovered across all ratepayers in the state – both those served by electric distribution companies and retail suppliers. This mechanism would likely still require new regulation and even legislation.

retail supplier in its service territory. A mechanism would also need to be established to allow those distribution companies to sell capacity to retail suppliers. Current regulations may not allow distribution companies to sell capacity to retail suppliers.

3. Amending RPS components: Regardless of whether an FRR is implemented, if REC prices increase to make up for the lost capacity revenues to renewables from the MOPR, RPS ACP caps may need to be increased to reflect this price increase. Similar changes may be needed to state legislation that create bill impact thresholds for utility power-purchase agreements for renewables. For example, some states have legislative ratepayer protections in place that include provisions for the maximum amount a customer bill can be impacted from investments in offshore wind, including caps on REC prices.[21] If the MOPR increases the costs of offshore wind and/or RECs, these bill impact thresholds may need adjustment.

Timing

In restructured markets, electric distribution companies typically hold auctions at a pre-determined time to procure supply for SOS customers. These contracts are typically a mix of short- and long-term, ranging from one to three years in length for residential and small-commercial customers and one year or less for larger commercial and industrial customers. For example, each year New Jersey conducts an auction in February for the four New Jersey electric distribution companies to procure electricity supply to serve their Basic Generation Service (equivalent of SOS) customers.[22]

The timing of these procurement auctions would need revision to align with an FRR, which requires a utility to commit to an FRR plan for five years, with each FRR capacity procurement process securing commitments to deliver electricity three years in the future.

States will also need to consider whether to continue requiring SOS to be a bundled product (*i.e.*, providing energy, capacity, and transmission, discussed below) that would all be procured according to the FRR schedule requirements or to carve out the energy and transmission procurements to stay on the existing SOS auction schedule.

Procurement Process and Oversight

Restructured states considering the FRR option will need to determine whether each electric distribution company should conduct its own procurement of capacity to meet the FRR requirements or whether they would rely on a state agency or other entity to administer centralized procurements on behalf of utilities.

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[21] For example, MD PUA § 7-704.1(e)(1)(iii) states "the projected net rate impact for all nonresidential customers considered as a blended average, combined with the projected net rate impact of other qualified offshore wind projects, does not exceed 1.5% of nonresidential customers' total annual electric bills, over the duration of the proposed OREC pricing schedule; and (iv) the price set in the proposed OREC price schedule does not exceed $190 per megawatt-hour in 2012 dollars."

[22] For residential and small commercial customers, the electric distribution companies use a rolling procurement structure, where each year one-third of the load is procured for a three-year period.

Some states have existing entities that are well-suited to conduct the needed procurement. For example, the Illinois Power Agency already oversees the procurement of energy and capacity to meet the needs of eligible retail customers for the state's investor-owned utilities and therefore could adapt to procuring capacity to meet an FRR obligation (see box on proposed Clean Energy Jobs Act in Illinois, SB2132; HB 3624).

Proposed Clean Energy Jobs Act would task the Illinois Power Agency with creating an alternate capacity auction. The Act would direct the Illinois Power Agency to take over the responsibility of procuring capacity for the ComEd service territory within PJM, prioritizing carbon-free generation.

If a state lacks such an agency, it may direct utilities to exit the PJM capacity market and conduct their own procurement process for capacity to meet the FRR obligation. In this case, state utility regulators would need to ensure that such procurements are competitive and that there is sufficient investigatory and enforcement authority in place to address affiliate deals and market power.

The procurement processes will need considerable oversight, regardless of whether a procurement is run by an agency or through the electric distribution companies. Procurement auctions for SOS in restructured states have historically been between distribution companies and power marketers,[23] not with generation units directly. In these cases, the power marketer bears the majority of the risk and employs a financial hedge to ensure competitive market pricing and delivery of load requirements, and PJM operates a competitive wholesale electricity market for generation capacity. With a move to the FRR option, regulators will need to revert to more of a regulated construct in which they would need to regulate the prudency and reasonableness of capacity contracts.

Finally, states will need to determine how to assess appropriate costs for capacity. For example, when reviewing an FRR, should a test for reasonableness be that it mirrors the market price from PJM? States will also need to decide whether the capacity procurement requirements under the FRR alternative should be bundled to include other components of retail service, such as energy, transmission, ancillary services, RECs, or other attributes.

Competition

States that restructured their electricity markets typically did so to address the anti-competitive monopoly structure of the electricity industry, improve service, and utilize market forces to drive down supply costs to customers. These needs still exist, and so it is important for states to think through how an FRR alternative would impact these pillars of restructuring and retail electricity competition.

States should address the following key items to assess impacts to competition:

[23] Business entities engaged in buying and selling electricity. Power marketers do not usually own generating or transmission facilities. Power marketers, as opposed to brokers, take ownership of the electricity and are involved in interstate trade. These entities file with the Federal Energy Regulatory Commission (FERC) for status as a power marketer. (Source: U.S. Energy Information Administration.)

- How will retail suppliers be impacted?
    - This includes how best to structure the payment for procured FRR capacity: Should retail suppliers purchase capacity from the electric distribution company for its portion of the load or should the FRR capacity costs be recovered across all customers, similar to distribution charges?
    - The FRR will require contracts for five years in length, committed to being available three years in the future. If a state decides to procure a bundled product in this manner and not just capacity, will this have a detrimental impact on competitive retail suppliers that typically rely on shorter-term contracts?
- As discussed in Step 2 above, states should also examine if there is sufficient diversity and quantity of capacity resources within an FRR zone to create competition and competitive pricing. If not, one solution to consider is a multi-state FRR to increase resource diversity.

States with Regulated Electric Markets

Regulated states have an easier path to exiting the PJM capacity market and implementing the FRR option. Within these states, vertically integrated utilities can own generation and use that generation to meet the demand of their customers. These utilities evaluate and identify a mix of generation resources necessary to meet their customers' projected energy and capacity needs through integrated resource plans. This can include building their own generation or contracting directly with generators. The resulting rates are then reviewed by the state utility commissions to assess if they are reasonable and in the public interest.

It is easier for a regulated state to pursue the FRR option for several reasons:

- Vertically integrated utilities are already procuring capacity to meet all load in their service territory, which is a key requirement of the FRR.
- Long-term planning in the form of IRPs ensures there is enough generation resource to serve existing load and forecasted load growth into the future. This is akin to what is required in the development of an FRR plan.
- Regulators have experience in reviewing IRPs and assessing the reasonableness of capacity costs.
- There is no retail choice and therefore no regulations to amend relating to compensation of capacity to the utility implementing the FRR and the retail supplier.

In addition, several of the regulated states have had experience with the FRR option. The American Electric Power FRR Plan covers portions of Virginia,[24] West Virginia, Indiana, and Michigan and the Duke Energy FRR covers Kentucky.

Actions for Regulated States

While there are fewer barriers to implementing the FRR in a regulated state, legislative action and regulatory considerations may still be needed. For example, even though there are existing FRR plans in regulated states, these have been on a voluntary basis. States would still need to adopt legislation to require utilities to exit the PJM capacity market and implement the FRR option.

CONCLUSION

FERC's December 2019 order expanding the reach of PJM's minimum offer price rule to "state-subsidized" resources represents a threat to lawfully-created state clean energy programs and utility consumers in PJM. If new renewable resources cannot clear the capacity auction, the cost for achieving state clean energy targets will rise. New clean energy providers that receive state support will not get financial credit for the capacity assurance they provide, and consumers will be forced to pay for excess capacity from legacy power providers that is not needed to meet PJM's reliability requirements.

PJM's FRR provides states with the option of opting out of participating in PJM's capacity market with the expanded MOPR. Under the FRR alternative, states work with their utilities and LSEs to develop a plan that secures sufficient capacity to meet forecasted demand for all customers within a designated FRR zone. An FRR plan must span five years once the FRR alternative has been selected.

The three-step framework provided here can guide and shape state decision-making about and planning around the possible pursuit of the FRR alternative. This guide identified important take-aways for states considering the FRR option.

First, a state should prioritize the issues that it is most interested in addressing through implementation of the FRR. Pertinent issues can include: state interests in boosting clean energy growth by providing capacity revenue to new renewable resources; incentivizing the entry of more clean energy resources into the market; or minimizing cost impacts to consumers. These issues will guide economic and financial and associated legislative and regulatory analyses that a state should undertake.

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[24] Virginia has retail electricity competition for non-residential customers. However, AEP's subsidiary in the FRR (Appalachian Power Company, or APCO) has not experienced load moving to a competitive supplier. To the extent a competitive supplier secures retail shopping load and chooses to have that load reflected in APCO's FRR capacity plan, the supplier would be required to compensate APCO for its capacity obligation in accordance with Section D.8 of Schedule 8.1 of the PJM Reliability Assurance Agreement (RAA). The purpose of the proposed formula rate is to calculate compensation for capacity made available to suppliers by APCO in accordance with the FRR.

Second, states should be aware that the path to the FRR alternative for states with restructured electricity markets may be less direct than in states with regulated electricity markets. Restructured states will likely need to take legislative and regulatory steps to instruct distribution utilities to implement the FRR option, govern the relationship between distribution companies and competitive retail suppliers, and align the timing of procurement auctions with the timing requirements of FRR plans. In contrast, vertically integrated utilities in regulated states are already in the practice of procuring capacity for their service territory and their regulators are experienced in assessing the reasonableness of capacity costs.

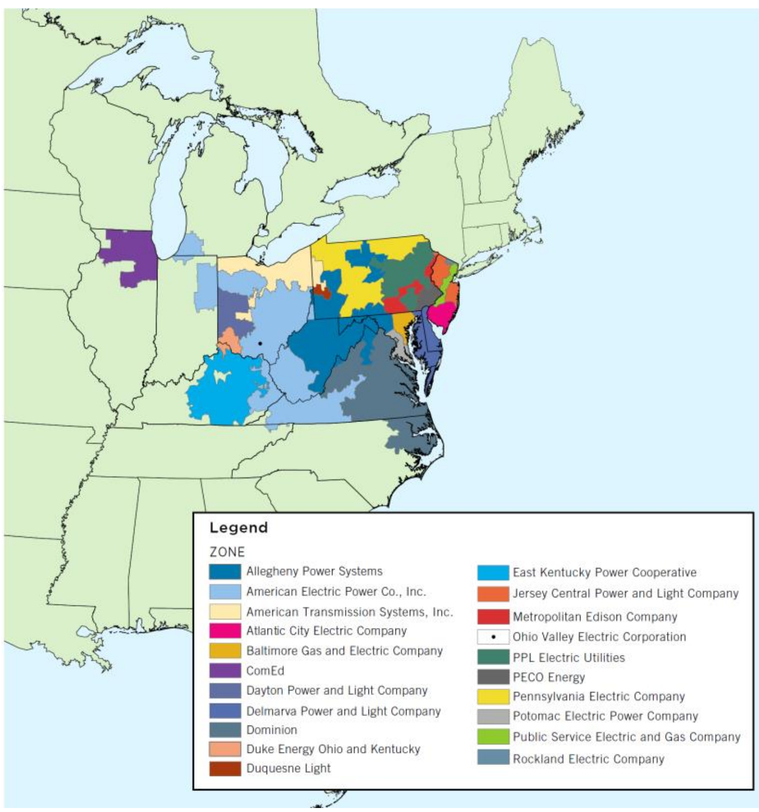
Third, irrespective of a state's regulated/restructured status, the FRR alternative may offer a number of economic and financial advantages to remaining in the capacity market with the expanded MOPR, which depends on state-specific circumstances. Requiring the adoption of an FRR plan will help consumers avoid paying twice for capacity and help states achieve clean energy targets within cost-protective measures for consumers. Yet states should be cognizant of the economic risks associated with the FRR alternative–the market could be less competitive than PJM's capacity market with greater market power for existing entities, likely increasing the cost of procuring capacity. With this in mind, if pursuing the FRR plan they should look to deploy regulatory measures that have been successfully used in the past to mitigate the threat posed by these risks.

Appendix A. Background on PJM's Capacity Market and the December 19, 2019 FERC MOPR Order

A.1. Introduction

PJM Interconnection is the regional transmission organization (RTO) responsible for coordinating the movement of wholesale electricity in all or parts of 13 states and the District of Columbia.[25] PJM meets the daily electricity demand for 65 million people and operates wholesale electricity markets with annual transactions of approximately $50 billion. The primary stated goal of PJM is to deliver reliable and affordable energy to customers and to engage in long-term planning to assure continued safe and reliable operation of the regional grid.

Figure 1. PJM territory served



Source: PJM Interconnect, available at https://www.pjm.com/library/~/media/about-pjm/pjm-zones.ashx.

[25] The 13 states include the following: Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia.

PJM operates both short-term (day-ahead) and real-time markets for energy and ancillary services.[26] Owners of generation sell energy and ancillary services into these markets, and utilities and LSEs purchase energy and ancillary services to meet the energy demand of their customers and applicable reliability standards. There are over 1,000 active participants in PJM's markets. PJM also runs a longer-term market for capacity, which is discussed next.

A.2. PJM's Reliability Pricing Model

PJM's capacity market is referred to as the Reliability Pricing Model (RPM) and has the stated goal to ensure enough generating capacity on the system to meet the forecasted systemwide demand for energy plus a required reserve margin. A reserve margin is necessary for the reliable operation of the grid to replace resources that may be forced off-line due to equipment failure or other factors. In PJM, the reserve margin is approximately 15.8 percent of the anticipated peak demand for power.

The RPM secures resource commitments to meet system peak loads three years in the future. Given physical limitations on the regional transmission system, PJM defines installed capacity requirements for transmission zones that are constrained in their ability to receive power from other regions. Thus, the installed capacity requirements can vary for what are referred to as Locational Deliverability Areas or LDAs.[27]

PJM runs RPM auctions, referred to as Base Residual Auctions (BRAs), each year in May for delivery three years in the future. PJM purchases capacity resources on behalf of LSEs who are charged for the generating capacity needed to serve their customers' peak energy demand. Figure 2 presents a sample supply and demand curve for PJM's May 2018 BRA for the capacity delivery year 2021/2022. Owners of existing generation and developers of new sources of generation that meet certain development thresholds qualify to participate in the BRA. Owners and developers offer capacity based on the price they are willing to accept, creating a capacity supply curve (blue line in Figure 2). PJM's RPM operates under a variable resource requirement (VRR) curve, which PJM constructs to represent the demand for capacity resources (red line in Figure 2).

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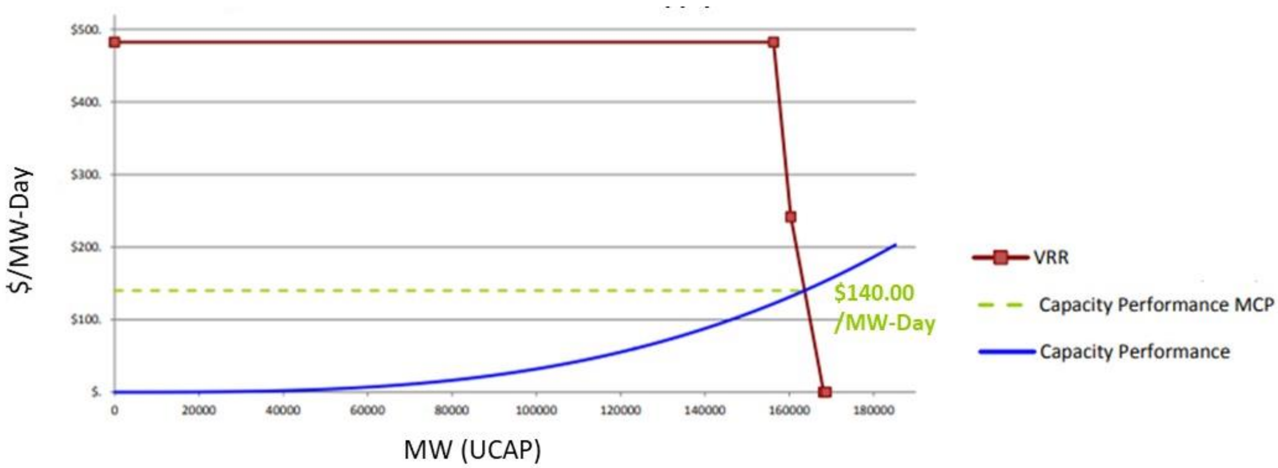
[26] Ancillary services help balance the transmission system as it moves electricity from generating sources to ultimate consumers. PJM operates several markets for ancillary services: the Synchronized Reserve Market, the Non-Synchronized Reserve Market, the Day-Ahead Scheduling Reserve Market and the Regulation Market. See, https://www.pjm.com/markets-and-operations/ancillary-services.aspx.

[27] The physical limits of the transmission system impact the amount of power that can be transferred between regions. For jurisdictions that select the FRR alternative discussed above, these limitations are used to determine the Minimum Internal Resource Requirement for each FRR zone.

Figure 2 - Example supply and demand curves for PJM's capacity market (2021/2022 Base Residual Auction RTO supply curve)



Source: PJM Interconnect, available at https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2021-2022/2021-2022-bra-supply-curves.ashx?la=en.

Figure 2 illustrates that the 2021/2022 BRA auction cleared at $140/MW-Day at approximately 164,000 MW. The VRR curve is inelastic until approximately 160,000 MW, which means that PJM is willing to pay a high price for capacity resources to meet the peak demand for energy plus the required reserve margin. The maximum price that PJM is willing to pay to acquire the needed capacity is set by the net cost of new entry (net CONE). Net CONE is the amount of compensation for capacity necessary to attract a developer of new capacity resources to the region. The VRR demand curve slopes steeply downward indicating rapidly diminishing willingness to pay for additional capacity resources beyond those necessary to meet peak demand plus the required reserve margin.

A.3. Implications of FERC's MOPR Ruling

FERC's December 19, 2019 MOPR ruling was the latest development linked to ongoing concerns about the operation of PJM's capacity market. Over several years, owners of coal- and natural gas-fired generators expressed concern that renewable and other resources, notably nuclear plants, receiving state subsidies were bidding into PJM's capacity market at artificially low prices that suppressed market prices. Eventually, a group of traditional generation owners submitted a complaint to FERC.[28]

[28] On March 21, 2016, pursuant to sections 206 and 306 of the Federal Power Act, 16 U.S.C. 824e and 825e (2012), and Rule 206 of the Federal Energy Regulatory Commission's (Commission) Rules of Practice and Procedure, 18 CFR 385.206 (2015), Calpine Corporation *et al*. filed a formal complaint against PJM alleging that its Open Access Transmission Tariff is unjust and unreasonable because it does not include provisions to prevent the artificial suppression of prices by existing generation resources that are the beneficiaries of out-of-market revenues, available at https://www.govinfo.gov/content/pkg/FR-2016-03-31/pdf/2016-07242.pdf.

In April of 2018, PJM submitted a filing to FERC with proposed capacity market rule changes to address generator concerns about the impact state subsidies were potentially having in the capacity market. In June of 2018, FERC rejected PJM's proposed capacity market rule changes but found that PJM's current capacity market resulted in "unjust" and "unreasonable" rates.[29] FERC further directed PJM to put on hold its next scheduled capacity market until PJM could develop acceptable market rules that responded to FERC's concerns about the operation of PJM's capacity market. The last BRA was conducted in May of 2018 for the 2021/2022 delivery year.

"From the beginning, this proceeding has been about two things: Dramatically increasing the price of capacity in PJM and slowing the region's transition to a clean energy future. Today's order will do just that. I strongly dissent from today's order as I believe it is illegal, illogical, and truly bad public policy."
FERC Commissioner Richard Glick

FERC's long-awaited December 19, 2019 order[30] directs PJM to make significant changes to the way it operates its capacity market. Specifically, FERC directed PJM to expand the application of the MOPR to all "state-subsidized" resources. Although all existing renewable energy resources are exempt, the order applies to all new renewable energy projects seeking to participate in PJM's capacity market that receive a state "subsidy"[31] and do not yet have an interconnection construction service agreement with PJM. The order also applies to all existing nuclear units. FERC's ruling in this matter was sharply divided in a 2 to 1 vote, with a strong dissent issued by Commissioner Glick (see box).

FERC's MOPR order will impact new renewable resources, including wind and solar resources that receive payments for the RECs they generate or are the result of a direct procurement with a state. These resources subject to MOPR will be forced to bid into PJM's capacity market at a predetermined minimum offer price floor, which is calculated based on net CONE. PJM's independent market monitor's preliminary estimates of net CONE and net ACR values[32] project that the minimum offer price floor for many new renewable resources would be above the BRA market clearing prices and thus the resources would not be selected to meet PJM's capacity requirements. As a result, new renewable resources will

[29] 163 FERC ¶ 61,236 available at https://www.ferc.gov/CalendarFiles/20180629212349-EL16-49-000.pdf.

[30] The FERC's December 19, 2019 Minimum Offer Price Rule (MOPR) Order Docket Nos. EL16-49-000 and EL18-178-000 (Consolidated) is available at https://www.ferc.gov/whats-new/comm-meet/2019/121919/E-1.pdf.

[31] FERC defined a state-subsidy in its December 19, 2019 MOPR Order as follows: "A direct or indirect payment, concession, rebate, subsidy, non-bypassable consumer charge, or other financial benefit that is (1) a result of any action, mandated process, or sponsored process of a state government, a political subdivision or agency of a state, or an electric cooperative formed pursuant to state law, and that (2) is derived from or connected to the procurement of (a) electricity or electric generation capacity sold at wholesale in interstate commerce, or (b) an attribute of the generation process for electricity or electric generation capacity sold at wholesale in interstate commerce, or (3) will support the construction, development, or operation of a new or existing capacity resource, or (4) could have the effect of allowing a resource to clear in any PJM capacity auction."

[32] Monitoring Analytics, Independent Market Monitoring for PJM. January 21, 2020. CONE and ACR Values—Preliminary is available at https://www.monitoringanalytics.com/reports/Reports/2020/IMM_CONE_ACR_Preliminary_Report_20200121.pdf.

not receive the benefit of ongoing capacity market revenues. The loss of this revenue will result in increased costs to states pursuing clean energy goals.

A second concern that stakeholder groups have raised regarding FERC's MOPR order is the potential for ratepayers to pay twice for capacity resources. Resources procured outside the PJM capacity market that do not count towards meeting reliability requirements, such as new renewable resources, will result in the procurement of more capacity than is necessary. This is in addition to persistent concerns that PJM's capacity market procures more capacity each year than is necessary to meet reliability standards. The reserve margin in PJM is generally around 16 percent of the forecast peak load; however, the RPM auction outcomes result in significantly more capacity procured than the reserve requirement, which have been equivalent to a 20 percent reserve margin.[33]

[33] Wilson, James. February 2020. Over-Procurement of Generating Capacity in PJM: Causes and Consequences, a report prepared for the Sierra Club and the Natural Resources Defense Council available at https://www.sierraclub.org/sites/www.sierraclub.org/files/blog/Wilson%20Overprocurement%20of%20Capacity%20in%20PJM.PDF.