UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Calpine Corporation, Dynegy Inc., Eastern Generation, LLC, Homer City Generation, L.P., NRG Power Marketing LLC, GenOn Energy Management, LLC, Carroll County Energy LLC, C.P. Crane LLC, Essential Power, LLC, Essential Power OPP, LLC, Essential Power Rock Springs, LLC, Lakewood Cogeneration, L.P., GDF SUEZ Energy Marketing NA, Inc., Oregon Clean Energy, LLC and Panda Power Generation Infrastructure Fund, LLC v. PJM Interconnection, L.L.C.	)	Docket No. EL16-49-000
PJM Interconnection, L.L.C.	)	ER18-1314-000, -001
PJM Interconnection, L.L.C.	)	EL18-178-000
	)	(consolidated)

BRIEF OF THE INDEPENDENT MARKET MONITOR FOR PJM

Monitoring Analytics, LLC, acting in its capacity as the Independent Market Monitor for PJM Interconnection, L.L.C.[1] ("PJM") ("Market Monitor"), submits this brief, and attached report (Attachment A), in response to the order issued in this proceeding

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

establishing a paper hearing process on June 29, 2018 ("June 29th Order").[2] The Market Monitor proposes a "Sustainable Market Rule" ("SMR") that builds on and is consistent with the Commission's decision about competitive markets and the intent of the resource specific FRR alternative approach.

The Commission has affirmed that it does not want the courts to curtail state actions, and that the Commission will take the necessary measures to protect competitive markets.[3] The June 29th Order confirms the Commission's commitment to defend competitive markets, and the Commission's concern about appropriately recognizing state policy goals. The Market Monitor presents here an alternative Sustainable Market Rule based on the Commission's reasoning and findings in the June 29th Order that is in part consistent with the Commission's FRR Alternative option and in part not, but that does meet the Commission's explicitly stated goals to preserve competitive markets and to respect states' policy objectives.[4]

The purpose of the Sustainable Market Rule is to maintain sustainable competitive markets in the face of significant nonmarket activity. The approach recognizes that the

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[2] *PJM Interconnection, L.L.C.*, 163 FERC ¶ 61,236.

[3] Br. for the United States and the Federal Energy Regulatory Commission as Amicus Curiae in Support of Defendants-Respondents and Affirmance, *EPSA v. Star*, No. 17-2445 (7th Cir May 29, 201) ("The Commission can exercise its responsibility under the Federal Power Act to ensure just and reasonable prices in the wholesale markets subject to its jurisdiction. The Court thus need not, and should not, resort here to the extraordinary and blunt remedy of preemption. Indeed, the interplay of state policies and wholesale markets—specifically how, and subject to what restrictions, generators that receive state support may participate in wholesale markets—is very much a live issue at the Commission. The Commission recently approved a proposal by the New England Independent System Operator to allow state-supported renewable resources to obtain wholesale capacity supply obligations… The Commission also is now considering whether PJM should revise its wholesale market rules to deal with the effects of state subsidies, including ZECs.").

[4] *See* June 29th Order at P 157 ("As noted, the Commission is initiating a paper hearing to address the just and reasonable replacement rate for PJM's existing MOPR, including the proposal identified above or any other proposal that may be presented.").

competitive PJM markets include energy, ancillary services and capacity markets. The approach recognizes the critical role of capacity markets in maintaining competitive markets. The approach does not attempt to limit in any way the impact of resources with nonmarket revenues on the energy market. Market resources should not be expected to be, or required to be, economically damaged by legitimate state policies intended to support renewable resources. It is essential that the competitive capacity market be permitted to continue to serve its essential balancing function in the overall PJM market design and offset declines in energy market revenue, whatever the source. While accommodating appears to imply that some price suppression in the capacity market is acceptable, price suppression below the competitive level in the capacity market should not be acceptable and is not consistent with a competitive market design. A better approach would be to harmonize the nonmarket activity with the market paradigm by designing an overall market structure (energy, ancillary services and capacity) that recognizes the role of state policies while preserving a competitive, market based construct to meet reliability goals in PJM. Harmonizing means that the integrity of each paradigm is maintained and respected. Harmonizing permits nonmarket resources to have an unlimited impact on energy markets and energy prices. Harmonizing means designing a capacity market to account for these energy market impacts, clearly limiting the impact of nonmarket revenues on the capacity market and ensuring competitive outcomes in the capacity market and thus for the overall competitive market.

I. COMMENTS

A. Commission's Goal to Preserve Competitive Markets and Respect State Policies.

In the June 29th Order (at P 149), the Commission determined "that PJM's existing Tariff is unjust and unreasonable." The Commission explained (at P 150):

> [The OATT] fails to protect the integrity of competition in the wholesale capacity market against unreasonable price distortions and cost shifts caused by out-of-market support to keep existing uneconomic resources in operation, or to support the uneconomic

> entry of new resources, regardless of the generation type or quantity of the resources supported by such out-of-market support. The resulting price distortions compromise the capacity market's integrity. In addition, these price distortions create significant uncertainty, which may further compromise the market, because investors cannot predict whether their capital will be competing against resources that are offering into the market based on actual costs or on state subsidies. Ultimately, these problems with PJM's existing Tariff result in unjust and unreasonable rates, terms, and conditions of service.

The Commission rejected the proposals in the record (at P 105), including a proposed Extended Minimum Offer Price Rule ("MOPR-Ex"), finding, "PJM's justifications do not adequately support the disparate treatment between resources receiving out-of-market support through RPS programs and other state-supported resources."

The Commission proposed an alternative (at PP 158–160), which combined an expanded MOPR applicable to all resource types with an "FRR Alternative" that would allow "on a resource-specific basis, resources receiving out-of-market support to choose to be removed from the PJM capacity market, along with a commensurate amount of load, for some period of time."

The Commission described its vision of a just and reasonable construct (at P 161):

> A resource receiving out-of-market support would not be prohibited from participating in the capacity market, but would be subject to the expanded MOPR, should it choose to offer into the market. In this manner, the resource-specific FRR Alternative would accommodate policies to provide out-of-market support to certain resources, but remove those resources from the market. This would essentially create a bifurcated capacity construct–resources receiving out-of-market support and a commensurate amount of load would be outside of the PJM capacity market, thereby increasing the integrity of the PJM capacity market for competitive resources and load.

The Commission has clearly defined its goals to preserve competitive markets and respect state policies. The details of the proposed FRR Alternative will not achieve the goal of preserving competitive markets because an unintended consequence of removing capacity and load for units most in need of nonmarket revenue, units that do not clear, is to suppress prices in the capacity market for all resources not receiving nonmarket payments.

However, the Commission's goals can be achieved with the proposed Sustainable Market Rule.

B. The Conundrum (A Tale of Two Markets).

It was the best of MOPRs, it was the worst of MOPRs, it was the best of markets, it was the worst of markets...[5]

The Commission is faced with a conundrum. The market is faced with a conundrum. How can PJM competitive wholesale power markets recognize state policy actions that favor specific types of energy producing resources while retaining the benefits of competitive markets and not returning to top down integrated resource planning and cost of service regulation? There are no easy answers. The existing approaches are not working. The Commission has, for clearly articulated reasons, rejected the proposals submitted to date.

One way to approach the question is to start with the current market design and its historical genesis in customers' wish to create competitive markets to avoid the construction of more uneconomic nuclear power plants under state cost of service regulation by permitting competition in the generation market which led first to PURPA and eventually to the creation of competitive wholesale power markets. The current market design, evolved from that era, has been successful, and even more so since the introduction of the RPM capacity market in 2007, in incenting entry of new resources with improved technology and exit of uneconomic resources. But the intensity of competition in the current market design has led to pressures to subsidize selected uneconomic resources, primarily

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5 With apologies to Charles Dickens. The entirety of the first sentence of A Tale of Two Cities is worth reading. Dickens, Charles. *A Tale of Two Cities*. Vintage Classics. Penguin Random House, 1990.

nuclear and coal, that could not successfully compete. In addition, as a result of a lack of federal policy on carbon, individual states have pursued aggressive approaches to subsidizing renewable resources.

The MOPR approach to noncompetitive entry evolved from its original (2006) design to limit market power exercised on behalf of load, to a response (2011) to proposals to subsidize specific units in specific states, to a design (2013) to address subsidies for gas-fired units that also incorporated exemptions, and to a return (2017) to the prior design.[6] [7] This third version of MOPR, based on a settlement among some market participants and PJM, was in effect from 2013 until 2017, when the Commission decision that approved the MOPR was remanded by the United States Court of Appeals for the District of Columbia Circuit for procedural reasons.[8] [9]

The Commission finds in its June 29th Order that the issues addressed by the various versions of MOPR are real and that the competitive markets, to be just and reasonable, must be protected from nonmarket resources. The Commission determined that PJM did not meet its section 205 burden to show that the MOPR-Ex proposal was just and reasonable and not unduly discriminatory. The Commission cited the disparate treatment among generation resources and exemptions for certain state sponsored RPS programs within the MOPR-Ex proposal.[10]

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6 *See PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,331 at P 103 (2006).

7 *See PJM Interconnection, L.L.C.*, 140 FERC ¶ 61,123 (2012); 135 FERC 61,022 (2011), *reh'g denied*, 137 FERC ¶ 61,145 (2011).

8 *See* NRG Power Marketing, LLC v. FERC, 862 F.3d 108, 117 (D.C. Cir. 2017).

9 For details on the MOPR changes, see "Analysis of the 2021/2022 RPM Base Residual Auction: Revised," <http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Analysis_of_the_20212022_RPM_BRA_Revised_20180824.pdf> (August 24, 2018).

10 *See* June 29th Order at P 105.

It is essential that any approach to the PJM markets and the PJM Capacity Market incorporate a consistent view of how the preferred market design is expected to work to provide competitive results in a sustainable market design over the long run. A sustainable market design means a market design that results in appropriate incentives to retire units and to invest in new units over time such that reliability is ensured as a result of the functioning of the market. There are at least two broad paradigms that could result in such an outcome. The market paradigm includes a full set of markets, most importantly the energy market and capacity market, which together ensure that there are adequate revenues to incent new generation when it is needed and to incent retirement of units when appropriate. This approach will result in long term reliability at the lowest possible cost.

The quasi-market paradigm includes an energy market based on LMP but addresses the need for investment incentives via the long term contract model or the cost of service model or the subsidy model. In the quasi-market paradigm, competition to build capacity is limited and does not include the entire PJM footprint. In the quasi-market paradigm, customers absorb the risks associated with investment in and ownership of generation assets through guaranteed payments under guaranteed long term contracts or the cost of service approach or the subsidy approach. In the quasi-market paradigm there is no market clearing pricing to incent investment in existing units or new units. In the quasi-market paradigm there is no incentive for entities without nonmarket revenues to enter and thus competition is effectively eliminated.

The market paradigm and the quasi-market paradigm are mutually exclusive as a way to structure wholesale power markets.

But there is another way to address the issues raised so starkly in the June 29th Order. It is possible to harmonize the paradigms rather than require the market paradigm to accommodate the nonmarket paradigm. There is a role for each paradigm, but each must be permitted to work on its own terms. Another way to approach the question is to ignore the accumulation of MOPR mechanics added to protect competitive markets, to recognize that both supporters of competitive markets and supporters of nonmarket approaches have legitimate goals, and to consider how to create a competitive wholesale power market starting with the existing asset and ownership mix and the existing and potential set of state energy policies.

The starting point must recognize that states have authority over generation and can choose to reregulate at any time. Although most PJM states have ceded authority over generation to wholesale power markets regulated by the Commission and many have created competitive retail markets that depend on competitive wholesale power markets, the states can reverse that decision. Nonetheless, state policies evince a distinction between the approach to traditional generation assets and renewable energy assets. States, for environmental policy reasons not directly related to competitive wholesale power markets, have created significant nonmarket payments for renewable energy under the general heading of renewable portfolio standards, RPS. States have pursued these policies, not to undercut competitive wholesale power markets, but to reduce carbon and other emissions. The impacts of these policies on markets are real and growing but are not the intended result of renewable energy policies.

The starting point must also recognize the role of competitive markets and that competitive markets need internally consistent rules in order to provide the incentives necessary for the markets to work.

The MOPR approach and its implicit impugning of nonmarket approaches should be replaced with an approach that recognizes the role of the market paradigm and the role of the nonmarket paradigm and that recognizes and defines the requirements for each to be successful. The intent and goals of the nonmarket paradigm, in all its variations, should be accepted as legitimate rather than maligned as being consciously antimarket. The nonmarket paradigm does not need to be characterized, in general, as an attempt to exercise market power or as a form of subsidy. Rather than assuming the market paradigm must be weakened in order to accommodate the nonmarket paradigm and rather than assuming that the nonmarket paradigm is antimarket, the paradigms need to be harmonized so that both can succeed in achieving their goals. The separate spheres of the market and nonmarket paradigms must be clearly defined so that each can work consistently and separately and on a sustainable basis.

C. Sustainable Market Rule

The starting place for the design of a new competitive wholesale power market includes three salient structural elements: state nonmarket revenues for renewable energy; a significant level of generation resources subject to cost of service regulation; and the structure and performance of the existing market based generation fleet. The relatively recent provision of nonmarket revenues to specific uneconomic existing resources, primarily nuclear power plants, is also a fact, but this is limited to a few units and is not widespread at present. The potential for additional nonmarket revenues for existing uneconomic coal and nuclear plants is also real, based on statements from the U.S. Department of Energy. The issue of nonmarket revenues for uneconomic existing resources must also be addressed in the design. Given that states have increasingly aggressive renewable energy targets, a core goal of a competitive market design should be to ensure that the resources required to provide reliability receive appropriate competitive market incentives for entry and for ongoing investment and for exit when uneconomic. A significant level of renewable resources, operating with zero or near zero marginal costs, will result in very low energy prices. Since renewable resources are intermittent, the contribution of renewables to meeting reliability targets must be analyzed carefully. The impact of renewables on energy prices in CAISO, and also SPP, illustrates the potential significance of the impact on energy prices and the relationship between zero cost energy from intermittent sources and reliability requirements.

In order to attract and retain adequate resources for the reliable operation of the energy market, revenues from PJM energy, ancillary services and capacity markets must be adequate for those resources. That adequacy requires a capacity market. In the SMR, the capacity market plays the essential role of equilibrating the revenues necessary to incent competitive entry and exit of the resources needed for reliability, with the revenues from the energy market that are directly affected by nonmarket sources. While it is theoretically possible to rely on an energy market with an administrative operating reserve demand curve designed to produce the same level of revenues as a capacity market, that is not a workable solution for the PJM market or potentially for any sustainable market in the presence of renewables and/or nonmarket resources. For PJM, a capacity market is the more cost effective and lower risk way to address revenue adequacy for the market resources required for reliability. Capacity markets exist only to permit the energy market to work. Capacity markets are a form of scarcity pricing. Capacity markets exist in order to ensure revenue adequacy for market units that produce energy. Capacity is not a physical product like energy. Light bulbs and air conditioners do not need capacity to operate; they need energy. Attempting to artificially increase energy prices by use of administrative operating reserve demand curves and other mechanisms in the face of increased penetration of zero marginal cost resources would be increasingly inconsistent with market based outcomes, is unlikely to be effective in countering the actual nature of energy supply and could lead to an erosion of the energy market by creating incentives to procure energy outside the organized market at actual marginal cost.

The Sustainable Market Rule recognizes and accepts the realities and rights of state policies, but also recognizes the authority of FERC to construct competitive wholesale power markets that are sustainable. The Sustainable Market Rule clearly defines the role and purpose of the capacity market and the role and purpose of the energy market.

The goal of the SMR is to recognize that competitive markets are essential to the provision of energy at the lowest possible cost and that competitive outcomes should not be compromised, and to recognize that states have the authority to provide nonmarket revenues to whatever resources they choose at whatever level they choose.

The Sustainable Market Rule recognizes that resources with nonmarket revenues will continue to increase, particularly renewable resources, and that resources with nonmarket revenues will unavoidably affect the energy market, and is designed to eliminate or minimize the impact of such resources on the capacity market. The purpose of the capacity market is to sustain the target level of market resources required for reliability based on market prices. There is no right to offer nonmarket resources in the capacity market at prices below the competitive level. No such right needs to be created in order to accommodate nonmarket resources in PJM markets. While the competitive market design, including energy, ancillary and capacity markets, must accommodate nonmarket resources, this does not mean that the competitive market design can or should be fundamentally undermined.

The Sustainable Market Rule is not a MOPR. The term MOPR was originally (2006) defined as a set of rules intended to prevent explicit attempts to exercise market power and suppress capacity market prices. The Sustainable Market Rule does not assume that the issue is the exercise of market power or explicit efforts to suppress capacity market prices. Similarly the SMR is not focused narrowly on explicitly defined subsidies and is not focused narrowly on specific nonmarket approaches including cost of service regulation. The SMR does not attempt to distinguish among the various types of nonmarket revenue from governmental actions in general, while excepting generally applicable federal policies. As a practical matter, there is no conceptual difference in impact on the competitive markets among the various types of nonmarket revenue. The SMR does not incorporate value judgments about which nonmarket revenue is good and which is not. The SMR focuses on the facts about the market and nonmarket approaches.

The purpose of the Sustainable Market Rule is to maintain sustainable competitive markets in the face of significant nonmarket activity. The approach recognizes that the competitive PJM markets include energy, ancillary services and capacity markets. The approach recognizes the critical role of capacity markets in maintaining competitive markets. The approach does not attempt to limit in any way the impact of resources with nonmarket revenues on the energy market. States have the authority to choose to provide nonmarket revenue to favored resources, regardless of markets and regardless of economics. Nonmarket resources can produce energy and sell energy at zero or low marginal cost without limit. But it is not appropriate to permit those nonmarket resources to suppress the capacity price for market resources. The capacity market was designed to ensure that market resources receive total market revenue adequate to provide incentives for entry and exit as needed. Capacity market prices are inversely related to energy market prices, albeit more slowly than optimal. When energy market revenues decline significantly, offers in the capacity market increase and the demand curve for capacity shifts and capacity market prices increase and the share of total market revenues from the capacity market increases. Market resources should face the same incentives and risks as they would face in a capacity market without nonmarket participation. Market resources should not be expected to be, or required to be, economically damaged by legitimate state policies intended to support renewable resources. It is essential that the capacity market be permitted to continue to serve its essential balancing function in the overall PJM market design and offset declines in energy market revenue, whatever the source. While accommodating appears to imply that some price suppression in the capacity market is acceptable, price suppression below the competitive level in the capacity market should not be acceptable and is not consistent with a competitive market design. Harmonizing means that the integrity of each paradigm is maintained and respected. Harmonizing permits nonmarket resources to have an unlimited impact on energy markets and energy prices. Harmonizing means designing a capacity market to account for these energy market impacts, clearly limiting the impact of nonmarket revenues on the capacity market and ensuring competitive outcomes in the capacity market and thus for the overall competitive market.

1. SMR Market Design

The SMR design is simple. All capacity has a must offer requirement and all capacity offers are included in the supply curve in the capacity market at competitive levels. All MW required for reliability are included in the capacity market demand curve (VRR curve). All cleared resources are paid the capacity market clearing price.

The SMR could be implemented fully in the next Base Residual Auction and would not require a transition mechanism.

2. Impact of SMR Market Design

Market and nonmarket resources that do not clear the capacity market based on their competitive offers are not paid a capacity price and are not given any special treatment in the wholesale power market. Any revenues required to sustain such resources would come from the energy and ancillary services markets and, for nonmarket resources, from nonmarket sources. Nonmarket resources that do not clear the capacity market would also be eligible to receive bonus payments under the capacity performance design for performance during performance assessment intervals, similar to energy only resources that perform without a capacity obligation.

The expected impact of the SMR design on the offers and clearing of renewable resources ranges from zero to insignificant. The competitive offers of renewables, based on the net avoidable costs of current technologies, are likely to clear in the capacity market. Allowing competitive renewable offers to clear in the market would have essentially the same impact as carving out such renewable resources using a resource specific FRR but without the need for complex federal and state rules.[11] [12]

The expected impact of the SMR design on the offers and clearing of cost of service resources depends on whether competitive offers of these resources, calculated without nonmarket revenues, clear in the capacity market. The competitive offers of cost of service resources, based on the net avoidable costs of the resources, are as likely to clear in the capacity market as other resources of comparable types. If competitive cost of service offers clear in the market, the result would have essentially the same impact as carving out such

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11 *See* "Scenario 2: Subsidy for Infra Marginal Resource," Attachment A at 21.

12 There may be a slight difference under the resource specific FRR as a result of the fact that the slope of the VRR curve changes slightly under the FRR approach.

renewable resources using a resource specific FRR but without the need for complex federal and state rules. If competitive cost of service offers would not clear, a resource specific FRR would suppress prices. In addition, cost of service resources have the option of using the existing FRR rules, which would retain their existing status.[13]

The expected impact of the SMR design on the offers and clearing of other resources with nonmarket revenues depends on the competitive offers of those resources.[14]

The Commission has observed and accepted (at P 159) that "some ratepayers may be obligated to pay for capacity both through the state programs providing out-of-market support and through the capacity market." The possibility that customers may pay twice has been accepted by the courts.[15]

3. Definition of Competitive Offer

In order to ensure the competitiveness of the capacity market and effectiveness of the capacity market in fulfilling its core equilibrating role, all resources with a must offer requirement continue to be required to make competitive offers in the capacity market. The definition of a competitive offer must be consistent with the definition of a competitive offer in the capacity performance capacity market. The definition of a competitive offer in the capacity market is currently Net CONE * B.[16] [17] But that definition of a competitive offer is

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13 Apparently anomalous results in the *MOPR/FRR Sensitivity Analyses of the 2021/2022 RPM Base Residual Auction* report are generally the result of specific nonlinearities in offers and clearing of specific offers made for specific and non-generalizable reasons.

14 Publicly owned utility means a Public Power Entity or an Electric Cooperative as defined in the PJM Reliability Assurance Agreement.

15 June 29th Order at P 69, citing *Connecticut Dept. of Pub. Util. Control v. FERC*, 569 F.3d 477, 481 (D.C. Cir. 2009) (Connecticut PUC); New Jersey Bd. of Pub. Utils. v. FERC, 744 F.3d 74, 97 (3rd Cir. 2014); New Eng. Power Generators Ass'n v. FERC, 757 F.3d 283, 295 (D.C. Cir. 2014).

16 In the capacity performance design, the default offer cap is the competitive offer level.

17 *See* Monitoring Analytics, "Analysis of the 2021/2022 RPM Base Residual Auction: Revised," at Attachment B (August 24, 2018).

not correct when there are no performance assessment hours or intervals, or when the nonperformance charge rate is not based on an accurate estimate of the expected number of performance assessment hours or intervals.[18] The definition of a competitive offer in the capacity market, following the mathematical logic of the capacity performance design, is the net avoidable cost rate (ACR) when there are no performance assessment hours or intervals or when the expected number of performance assessment intervals or hours is less than that used in the calculation of the nonperformance charge rate.[19] PJM's repricing proposal in this matter ignores the inconsistency and would use net ACR to define competitive offers for its repricing proposal MOPR but Net CONE * B to define competitive offers for those resources not subject to PJM's proposed MOPR. It is not an acceptable or reasonable market design to have two different definitions of a competitive offer in the same market. It is critical that the definitions be the same, regardless of the reason for application, in order to keep price signals accurate and incentives consistent. The definition of a competitive offer should follow the fundamental economic logic that applies to capacity performance resources, as submitted by PJM in response to the Commission's deficiency letter in the Capacity Performance proceeding, with appropriate accurate estimates for the input assumptions used.[20] [21]

If PJM continues to define Net CONE * B as the competitive offer in the capacity market, then Net CONE * B must be the definition of a competitive offer for all capacity resources including those with nonmarket revenues.

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18 *Id.*

19 *Id* at 86–87.

20 *See* Response of PJM Interconnection, L.L.C. to Commission's March 31, 2015 Information Request, Docket No. ER15 – 623-000 (April 10, 2015).

21 *See* Monitoring Analytics, "Analysis of the 2021/2022 RPM Base Residual Auction: Revised," at Attachment B (August 24, 2018).

If Net CONE * B is not the definition of a competitive offer, under the capacity performance logic, competitive offers in the capacity market are defined to be net ACR, based on unit specific facts, or technology defaults if applicable, for gross ACR and unit specific net revenue. Resources that can demonstrate that they receive no nonmarket revenues or support would be presumed to be competitive.

Prior attempts to distinguish between the definition of competitive offers of new entrants and the competitive offers of existing resources were a mistake, as is PJM's continued application of that approach in its repricing proposal. A competitive offer is a competitive offer, regardless of whether the resource is new or existing. The prior approach of defining a high competitive offer for a new entrant, equal to the net cost of entry for the resource, and then eliminating any requirement in year two, illustrates the fallacy. Resource owners enter and remain in the market with the expectation that they will recover their costs and earn a return on and of capital. That is true of new entrants and existing resources. A competitive offer in the capacity market is the marginal cost of capacity, or net ACR, regardless of whether the resource is planned or existing. The energy market appropriately does not recognize a difference in the definition of marginal cost between the offers of new, or planned, units and the offers of existing units. Neither should the capacity market.

4. Definition of Nonmarket Revenue

The Sustainable Market Rule defines nonmarket revenue for a resource generally as all revenue not received under a tariff regulated by the Commission, which would principally include PJM market revenues. Specifically, the proposed definition of nonmarket revenue is:

> Formal or informal agreements or arrangements to seek, recover, accept or receive any (1) material payments, concessions, rebates, or subsidies directly or indirectly from any governmental entity connected to the construction, development, operation, or clearing in any RPM Auction, of the Capacity Resource, that are not received under a tariff regulated by the Commission and administered by PJM, (2) other material support or payments

> obtained in any state-sponsored or state-mandated processes, connected to the construction, development, operation, or clearing in any RPM Auction, of the Capacity Resource, or (3) revenue attributable to the inclusion of costs of the resource in an LSE's retail rates. Nonmarket revenue shall not include federal government production tax credits, investment tax credits, and similar tax advantages or incentives that are available to generators without regard to the technology, fuel type, or geographic location of the generation.[22]

The SMR proposed definition of nonmarket revenues is broad and therefore not discriminatory.[23] The definition is based directly on the definition in the PJM tariff prior to the remand order in the NRG case. Consistent with the definitions in that tariff, the proposed definition of nonmarket revenues excludes only nonmarket revenues generally available under federal programs. The rule contributes to ensuring competition in the PJM markets and in the PJM capacity market by addressing all relevant nonmarket revenues.

5. Existing FRR Design

The existing FRR approach remains an option for vertically integrated utilities with no retail choice, including both privately and publicly owned utilities. Such utilities have had and continue to have the ability to opt out of the capacity market and provide their own capacity. There is no reason for any special exemptions for such utilities. Such utilities have the option to use the existing FRR option if they plan to continue to be cost of service based.

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22 This language is based on the definition of Material Subsidy in the proposed MOPR-Ex tariff language. See "Attachment D Revisions to the PJM Open Access Transmission Tariff – Option B", *PJM Interconnection, L.L.C.*, Docket No. ER18-1314-000, April 9, 2018.

23 Nonmarket resources include, among others. all resources that receive revenues based on cost of service regulation, whether private utility or publicly owned utility. The term nonmarket is intended to be a factual description of whether a resource receives nonmarket revenues, as defined. Publicly owned utility means a Public Power Entity or an Electric Cooperative as defined in the PJM Reliability Assurance Agreement.

> A Party is eligible to select the FRR Alternative if it (a) is an IOU, Electric Cooperative, or Public Power Entity; and (b) demonstrates the capability to satisfy the Unforced Capacity obligation for all load in an FRR Service Area, including all expected load growth in such area, for the term of such Party's participation in the FRR Alternative.[24]
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> A Party eligible under B.1 above may select the FRR Alternative only as to all of its load in the PJM Region; provided however, that a Party may select the FRR Alternative for only part of its load in the PJM Region if (a) the Party elects the FRR Alternative for all load (including all expected load growth) in one or more FRR Service Areas; (b) the Party complies with the rules and procedures of the Office of the Interconnection and all relevant Electric Distributors related to the metering and reporting of load data and settlement of accounts for separate FRR Service Areas; and (c) the Party separately allocates its Capacity Resources to and among FRR Service Areas in accordance with rules specified in the PJM Manuals.

An entity must request to elect the existing FRR option no later than four months prior to the Base Residual Auction for the first delivery year of the election.[25] An entity must under the existing FRR option submit its FRR capacity plan no later than one month prior to the Base Residual Auction for the effective delivery year.[26] The minimum term for election of the existing FRR option is five consecutive delivery years. Under the existing FRR option, an entity may terminate its FRR election following the minimum term by providing written notice to PJM no later than two months prior to the Base Residual Auction for the effective delivery year.[27] In the event of a State Regulatory Structural Change, an entity may elect or terminate its FRR election by providing written notice to

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24 "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 8.

25 *See* RAA Schedule 8.1.

26 *Id*.

27 *Id*.

PJM no later than two months prior to the Base Residual Auction for the effective delivery year.[28]

Public power entities and electric cooperatives could use the existing FRR option if they plan to continue to be cost of service based. To request the existing FRR option, public power entities or electric cooperatives need to demonstrate that the identified service area meets the definition of FRR Service Area as defined in the RAA. The definition of FRR Service Area provides that "In the event that the service obligations of an Electric Cooperative or Public Power Entity are not defined by geographic boundaries but by physical connections to a defined set of customers, the FRR Service Area in such circumstances shall be defined as all customers physically connected to transmission or distribution facilities of such Electric Cooperative or Public Power Entity within an area bounded by appropriate wholesale aggregate metering as described above."[29]

The Market Monitor recommends that the existing capacity performance rules for FRR resources be modified to eliminate the physical nonperformance assessment option in order to ensure comparability across all capacity resources in PJM. Currently, FRR entities are given the option of electing to be subject to either financial nonperformance assessment or physical nonperformance assessment.

6. Summary

Under the SMR, all nonmarket resources may participate in the energy market without limits. This includes renewables, behind the meter resources, cost of service units, coal and nuclear units with nonmarket revenues, and any and all energy producing resources. But to ensure that PJM continues to meet its reliability obligations, the capacity market needs to be the balancing mechanism for the market resources needed for reliability

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[28] *Id*.

[29] *Id*.

to ensure the appropriate incentives for entry and exit. This balancing function requires that all capacity resources must offer at competitive levels.

If resources offer at competitive levels and clear the capacity market, the resources are paid the market clearing price. If resources do not clear the capacity market, the resources are not paid for capacity. Any nonmarket revenues required to meet the public policy or other goals associated with these resources will be provided outside the market in whatever manner the supporters of those resources choose.

Vertically integrated utilities may opt for the existing FRR option.[30] This is equivalent to the Commission's FRR option but for an entire service territory. It is expected that the selection of this option will not have an impact on capacity market prices.

If renewable resources do not clear in the capacity market, these renewable resources will need to rely on nonmarket revenues to make up any revenue shortfall.

If coal and nuclear resources do not clear in the capacity market, these resources will need to rely on nonmarket revenues to make up any revenue shortfall.

The SMR is simple, based in economic logic and does not require complex rule changes to implement. The SMR would provide a straightforward way to harmonize federal and state approaches to the provision of energy, while respecting the distinction between federal and state authority.

D. Other Proposals

The proposed Sustainable Market Rule is preferable to the identified alternatives. The Market Monitor will respond to any other alternatives defined in initial briefs.

1. Resource Specific FRR

The resource specific FRR approach is intended to remove nonmarket capacity and matching load from the market with the goal of reducing or eliminating the market impacts

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30 *Id*.

of subsidies. But that will not be the result of the resource specific FRR approach. The only significant difference in impact between the SMR and resource specific FRR approach is the case of resources that do not clear in the capacity market or would not clear in the capacity market at a competitive offer level. When these extramarginal units are removed from the capacity market with matching load, the result is significant price suppression below the competitive market level. (See Attachment A) In the case of resources that clear the capacity market based on competitive offers (inframarginal), there will be no price impacts from the resource specific FRR approach. For these inframarginal resources, the Sustainable Market Rule will produce the results intended by the Commission but without the need for a complex resource specific FRR construct.

The Market Monitor has prepared a report on the impacts of the resource specific FRR, and has attached a copy to this filing.[31] The report shows what would have happened if the 2021/2022 BRA had been conducted under various assumptions regarding the selection of the resource specific FRR option.[32] The analysis assumes as a baseline the results of the 2021/2022 BRA and implicitly that the resource offers in the 2021/2022 BRA did not include subsidies.[33] Although some offers likely did include subsidies, the scenario results are useful in establishing a lower bound on the actual expected impact of the resource specific FRR option. If additional cleared resources had been identified as

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

32 For this sensitivity analysis, the reliability requirement for each LDA was adjusted by the unforced capacity (UCAP) MW of the identified resources within the same LDA. The Variable Resource Requirements (VRR or demand curves) were derived using the adjusted reliability requirement and target installed reserve margin, which could differ from the reserve margin calculated based on the cleared capacity.

33 Apparently anomalous results in the *MOPR/FRR Sensitivity Analyses of the 2021/2022 RPM Base Residual Auction* report are generally the result of specific nonlinearities in offers and clearing or specific offers made for specific and non-generalizable reasons.

receiving subsidies and would not have cleared without the subsidies, the price impacts of the resource specific FRR approach would have been larger. Each of the resource specific FRR scenarios shows that the resource specific FRR method would suppress capacity prices. Even under the conservative assumption that only 2,000 MW were designated as resource specific FRR capacity, the analysis shows a 13.4 percent decrease in the RTO capacity clearing price. If 12,000 MW were designated as resource specific FRR capacity in the 2021/2022 BRA, the RTO clearing price would have decreased by 50 percent.

In addition to scenarios that designate 2,000 MW, 4,000 MW, 6,000, MW, 8,000 MW, 10,000 MW and 12,000 MW as resource specific FRR capacity, the report includes scenarios that consider specific resource groups such as cost of service units, units at risk of retirement, wind and solar units, and coal and nuclear units. In the sensitivity in which cost of service units totaling 34,114.6 MW of capacity were designated as resource specific FRR capacity, the RTO clearing price would have decreased by 39.5 percent. The clearing prices in the other LDAs would have decreased by 1.0 percent to 8.2 percent. The BGE clearing price would have decreased by $0.10 per MW-day or 0.0 percent.

The Market Monitor identified units at risk of retirement totaling 23,741.1 MW of capacity.[34] If the units at risk had been designated as resource specific FRR capacity in the 2021/2022 BRA, the RTO clearing price would have decreased by 50 percent. The clearing prices in the other LDAs would have decreased by 0.2 percent to 65.1 percent.

If 25 percent of coal and nuclear capacity (18,866.3 MW) had been designated as resource specific FRR capacity in the 2021/2022 BRA, the RTO clearing price would have decreased by 28.4 percent. Other LDAs would have experienced price decreases ranging from 15.0 percent to 19.7 percent. If 100 percent of coal and nuclear capacity (75,496.2 MW) had been designated as resource specific FRR capacity in the 2021/2022 BRA, the RTO clearing price would have decreased by 82.1 percent. Other LDAs would have experienced

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[34] Units at risk are defined in footnote 9 of Attachment A.

price decreases ranging from 1.0 percent to 85.4 percent. The MAAC clearing price would have increased 7.8 percent.

The general conclusion, based on the reported sensitivities, is that removal of inframarginal units and associated load does not affect prices and that removal of extramarginal units and associated load does significantly suppress prices.

2. PJM's Repricing Proposal

PJM's revised pricing proposal modifies the original repricing proposal by requiring subsidized resources that choose the resource specific FRR option to offer at $0 per MW-day and by paying the clearing price in the form of an opportunity cost, without any performance obligation, to units that would clear in a competitive market but do not clear in PJM's approach. The result is a large increase in cost to customers.

PJM proposes to clear the auction in two stages.[35] In the first stage, all subsidized resources that choose the resource specific FRR option would be entered into the auction at $0 per MW-day. In the second stage, the auction would be cleared after removing the offers of the resource specific FRR capacity. The reliability requirement, VRR curves and capacity import limits of every LDA would be kept the same in both stages of the auction clearing. The clearing quantities would be obtained from the solution of the first stage auction. The clearing prices would be set by the second stage of the auction clearing. Any capacity that cleared only in the second stage of auction clearing would be paid an opportunity cost (now renamed incorrectly as inframarginal rent) equal to the difference between the clearing price and offered price, but would not be treated as cleared capacity resources and would not take on any performance obligations.

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35 See Meeting Materials for the Markets and Reliability Committee Special Session: PJM Response to FERC on Capacity Market Reforms, "PJM Proposal including Stakeholder Input," September 11, 2018, <https://www.pjm.com/-/media/committees-groups/committees/mrc/20180911-special/20180911-pjm-proposal-including-stakeholder-input.ashx>.

The Market Monitor's report in Attachment A includes two scenarios that analyze the impacts of PJM's two stage resource specific FRR approach. In one scenario, the units at risk of retirement totaling 23,741.1 MW were designated as resource specific FRR capacity under the PJM method.[36] The second stage RTO clearing price was $234.67 per MW-day, an increase of 67.6 percent with respect to the actual RTO clearing price in the 2021/2022 BRA. The increase in price is attributable to the removal of 23,741.1 MW from the supply curve in the second stage. This caused a leftward shift of the supply curve while the VRR curve remained constant, leading to a higher clearing price. The price increases in the other LDAs were also significant, ranging from 20.0 percent to 213.6 percent. If units at risk of retirement elected the resource specific FRR, the auction were cleared under the PJM's proposed repricing method, and everything else remained the same, the Market Monitor estimates that the load obligation, including subsidies and lost opportunity payments, would have been $17.7 billion, an increase of 90.8 percent compared to the actual results of the 2021/2022 BRA.[37]

In the second scenario under the PJM repricing approach, units at high risk of retirement (11,777.2 MW) were designated as resource specific FRR capacity.[38] The RTO clearing price would have increased 29.0 percent over the actual RTO clearing price in the 2021/2022 BRA. The clearing prices in other LDAs would have increased from 2.3 percent to 16.7 percent. The PSEG clearing price remained the same and the BGE clearing price decreased by 9.8 percent. If units at high risk of retirement elected the resource specific FRR, the auction were cleared under the PJM's proposed repricing method and everything

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36 For this scenario it was assumed that all units at risk were subsidized and chose the resource specific FRR option. Alternatively, if a unit at risk chose to be subject to the MOPR under the PJM proposal and the resource cleared the auction, the price increase would have been smaller.

37 See footnote 12 in Attachment A for information on subsidy levels used in this analysis .

38 See footnote 13 in Attachment A for a description of units at high risk of retirement.

else remained the same, the Market Monitor estimates that the load obligation, including subsidies and lost opportunity payments, would have been $10.9 billion, an increase of 17.4 percent compared to the actual results of the 2021/2022 BRA.

The sensitivity results for the PJM revised repricing proposal are based on the specific levels of MW identified and the specific units. The results are a function of the level of MW identified. In addition, if all of the subsidized capacity were extramarginal in the 2021/2022 BRA, the second stage auction prices would be the same as the clearing prices in the 2021/2022 BRA.

II. CONCLUSION

The Market Monitor respectfully requests that the Commission afford due consideration to these comments on brief as the Commission resolves the issues in this proceeding.

Respectfully submitted,

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Dated: October 2, 2018

CERTIFICATE OF SERVICE

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

Dated at Eagleville, Pennsylvania,
this 2nd day of October, 2018.

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Attachment A

MOPR/FRR Sensitivity Analyses of the 2021/2022 RPM Base Residual Auction

The Independent Market Monitor for PJM

September 26, 2018

Table of Contents

Introduction

This report, prepared by the Independent Market Monitor for PJM (IMM or MMU), addresses and quantifies the impact of potential MOPR/FRR scenarios on market outcomes in the Reliability Pricing Model (RPM) Base Residual Auction (BRA) (for the 2021/2022 Delivery Year) which was held from May 10 to 16, 2018.[1]

This report addresses, explains and quantifies the market outcomes of applying unit specific Fixed Resource Requirement (FRR) in defined ways.[2]

Conclusions and Recommendations

The results of the analysis show that removing units and associated load from the markets, as defined by the resource specific FRR approach, significantly reduces capacity market prices when the removed resources did not clear the auction (extra marginal resource). This is not surprising because, in such cases, removing matching load means that the demand curve is shifted while removal of the supply that did not clear does not affect the outcome. The removed supply is offered at prices above the clearing price. In such cases, the price impacts result from the shift of the demand curve to the left without a corresponding shift of the supply curve. The results of the resource specific FRR approach when the removed resources did clear the auction (infra marginal resources) is generally not significant. In such cases, a segment of the supply curve is removed from the supply that cleared and the demand curve is shifted to the left.[3]

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1 The MMU performs sensitivity analyses for each RPM Base Residual Auction. The MMU has developed an algorithm to replicate the results of Base Residual Auction. The results of the 2021/2022 RPM Base Residual Auction conducted by PJM were replicated using the MMU's approach. The total MW cleared and clearing prices for every constrained LDA using the MMU's algorithm were identical to the corresponding total MW cleared and clearing prices under PJM's method. For details on the clearing process and the MMU's method, see Attachment A to the "Analysis of the 2021/2022 RPM Base Residual Auction Revised," <http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Analysis_of_the_20212022_RPM_BRA_Revised_20180824.pdf> (August 24, 2018).

2 The values stated in this report for the RTO and LDAs refer to the aggregate level including all nested LDAs unless otherwise specified. For example, RTO values include the entire PJM market and all LDAs. Rest of RTO values are RTO values net of nested LDA values.

3 See Attachment for illustration through a simple two LDA example of how clearing prices are affected by subsidies for extra marginal and infra marginal resources.

The results show that there are significant price impacts across the range of MW subject to resource specific FRR. There is no safe level and no level of resource specific FRR that would not significantly suppress prices. For example, with only a 2,000 MW level of resource specific FRR, for units that did not clear the auction, the resource specific FRR option reduces rest of RTO prices by 13.4 percent.

PJM's approach would result in a significant increase in capacity prices and in the cost of capacity. Under PJM's proposed repricing method using a two stage auction clearing, the clearing quantities are obtained in the first stage auction where all the subsidized resources are included in the market clearing with offers at $0 per MW-day.[4] The clearing prices are determined in the second stage auction, where the subsidized resources are removed from the supply while the VRR requirements are left unchanged. The sensitivity results show a substantial impact on clearing prices and revenues. Additional high priced offers need to be cleared in the second stage auction in order to the meet the same demand curve with reduced supply. Under PJM's proposal, the additional high priced capacity that cleared in the second stage auction but not the first would not take on any capacity performance obligations despite setting clearing prices and being paid the lost opportunity cost.

Table 1 Scenario summary of change in rest of RTO market clearing prices: 2021/2022 RPM Base Residual Auction

Scenario Description	Rest of RTO Clearing Price ($ per MW-Day)	Change ($ per MW-Day)	Change Percent	FRR Capacity (UCAP MW)
Actual Results	$140.00			
FRR for Cost of Service Units	$84.77	($55.23)	(39.5%)	34,114.6
FRR for Units at Risk of Retirement	$70.00	($70.00)	(50.0%)	23,741.1
FRR for Annual Wind and Solar Units	$140.00	$0.00	0.0%	1,257.1
FRR for 25 percent of Coal and Nuclear Resource MW	$100.21	($39.79)	(28.4%)	18,866.3
FRR for 50 percent of Coal and Nuclear Resource MW	$69.96	($70.04)	(50.0%)	37,732.7
FRR for 100 percent of Coal and Nuclear Resource MW	$25.00	($115.00)	(82.1%)	75,496.2
FRR for 2,000 MW Extra Marginal Supply	$121.21	($18.79)	(13.4%)	2,000.0
FRR for 4,000 MW Extra Marginal Supply	$107.20	($32.80)	(23.4%)	4,000.0
FRR for 6,000 MW Extra Marginal Supply	$93.50	($46.50)	(33.2%)	6,000.0
FRR for 8,000 MW Extra Marginal Supply	$84.77	($55.23)	(39.5%)	8,000.0
FRR for 10,000 MW Extra Marginal Supply	$78.44	($61.56)	(44.0%)	10,000.0
FRR for 12,000 MW Extra Marginal Supply	$69.98	($70.02)	(50.0%)	12,000.0
FRR for Units at Risk of Retirement (PJM's Repricing Method)	$234.67	$94.67	67.6%	23,741.1
FRR for Units at High Risk of Retirement (PJM's Repricing Method)	$180.62	$40.62	29.0%	11,777.2

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4 See Meeting Materials for the Markets and Reliability Committee Special Session: PJM Response to FERC on Capacity Market Reforms, "PJM Proposal including Stakeholder Input", September 11, 2018, <https://www.pjm.com/-/media/committees-groups/committees/mrc/20180911-special/20180911-pjm-proposal-including-stakeholder-input.ashx>.

Results

For this analysis, the reliability requirement is adjusted by the unforced capacity (UCAP) MW of the identified resources, except when simulating PJM's proposed two stage auction clearing because the demand curve is not adjusted in PJM's approach. Based on the mathematical definition of the Variable Resource Requirement (VRR or demand curve), the reduction in the reliability requirement results in a slight change in the slope of the VRR curve and the shift in the VRR curve is not parallel.[5] For this analysis, the resources are matched to the LDA reliability requirement based on the defined modeled LDA of the resource. Unlike the current FRR application where the resources in an FRR plan are not known until closer to the start of the relevant delivery year, the unit specific FRR resources would be identified at the time of the auction. Since the location of the unit specific FRR resource would be identified, the LDA Minimum Internal Resource Requirements are not needed and are not applied in this analysis except in the case of existing FRR plans, and all existing Capacity Emergency Transfer Limits (CETL) are respected.[6]

Table 1 summarizes the results of the sensitivity analyses, using price impacts for Rest of RTO for each sensitivity.

Impact of FRR for Resources with Cost of Service Regulation

Table 2 shows the results of the 2021/2022 RPM Base Residual Auction if resources with cost of service regulation, including public power resources, had elected the resource specific FRR option. In the 2021/2022 Base Residual Auction, cost of service and public power resources accounted for 34,114.6 MW of offered capacity.[7] In the 2021/2022 RPM

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5 See Attachment.

6 "PJM Manual 18: PJM Capacity Market," Rev. 40 (Feb. 22, 2018) at 225-226. An LDA has a defined import capability, Capacity Emergency Transfer Limit (CETL), to import resources from outside the LDA. FRR entities are allowed to account for this import capability by including resources from outside the LDA in their FRR capacity plan. The Minimum Internal Resource Requirement is defined as the (LDA Reliability Requirement – LDA CETL)/(LDA Preliminary Zonal Peak Load Forecast * FPR). The FRR obligation is multiplied by the LDA Minimum Internal Resource Requirement to determine the reduction in the LDA reliability requirement.

7 Unless otherwise specified, all volumes and prices are in terms of unforced capacity (UCAP), which is calculated as installed capacity (ICAP) times (1-EFORd) for generation resources and as ICAP times the Forecast Pool Requirement (FPR) for demand resources and energy efficiency resources. The EFORd values in this report are the EFORd values used in the 2021/2022 RPM Base Residual Auction.

Base Residual Auction, the import constraints for ATSI, ComEd, EMAAC, PSEG and BGE were binding. The results of the sensitivity show that the ComEd, ATSI, EMAAC, PSEG, and BGE import constraints would have remained binding and the DEOK import constraint would have been binding.

The RTO clearing price would have decreased by $55.23 per MW-day to $84.77 per MW-day. The ATSI clearing price would have decreased by $7.32 per MW-day to $164.01 per MW-day. The ComEd clearing price would have decreased by $6.54 per MW-day to $189.01 per MW-day. The EMAAC clearing price would have decreased by $0.73 per MW-day to $165.00 per MW-day. The PSEG clearing price would have decreased by $0.13 per MW-day to $204.16 per MW-day. The BGE clearing price would have decreased by $0.10 per MW-day to $200.20 per MW-day. The DEOK clearing price would have decreased by $11.53 per MW-day to $128.47 per MW-day.

Table 2 Impact of cost of service and public power units electing resource specific FRR: 2021/2022 RPM Base Residual Auction[8]

Scenario 1

LDA	Base Residual Auction Clearing Price ($ per MW-Day)	FRR for Cost of Service Units Clearing Price ($ per MW-Day)	Change ($ per MW-Day)	Change Percent	FRR Capacity (UCAP MW)
RTO	$140.00	$84.77	($55.23)	(39.5%)	34,114.6
ATSI	$171.33	$164.01	($7.32)	(4.3%)	
ComEd	$195.55	$189.01	($6.54)	(3.3%)	
EMAAC	$165.73	$165.00	($0.73)	(0.4%)	
PSEG	$204.29	$204.16	($0.13)	(0.1%)	
BGE	$200.30	$200.20	($0.10)	(0.0%)	
DEOK	$140.00	$128.47	($11.53)	(8.2%)	

Impact of FRR for Resources at Risk of Retirement

Table 3 shows the results of the 2021/2022 RPM Base Residual Auction if units at risk of retirement had elected the resource specific FRR option. In the 2021/2022 Base Residual Auction, units at risk of retirement accounted for 23,741.1 MW of offered capacity.[9] In

8 The FRR Capacity (UCAP MW) is specified only for the entire RTO to maintain data confidentiality.

9 Non-nuclear units that have not recovered avoidable costs from total market revenues in two of the last three years or have not cleared either the 2019/2020 or the 2020/2021 capacity auctions are considered at risk of retirement. The non-nuclear MW at risk are lower than reported in the State of the Market Report because units that have subsequently started the

the 2021/2022 RPM Base Residual Auction, the import constraints for ComEd, ATSI, EMAAC, PSEG and BGE were binding. The results of the sensitivity show that the ComEd, EMAAC and PSEG import constraints would have remained binding, BGE import constraint would not have been binding and the DEOK import constraint would have been binding.

The RTO clearing price would have decreased by $70.00 per MW-day to $70.00 per MW-day. The ATSI clearing price would have decreased by $101.33 per MW-day to $70.00 per MW-day. The ComEd clearing price would have decreased by $6.53 per MW-day to $189.02 per MW-day. The EMAAC clearing price would have decreased by $0.26 per MW-day to $165.47 per MW-day. The PSEG clearing price would have decreased by $0.76 per MW-day to $203.53 per MW-day. The BGE clearing price would have decreased by $130.30 per MW-day to $70.00 per MW-day. The DEOK clearing price would have decreased by $11.53 per MW-day to $128.47 per MW-day.

Table 3 Impact of units at risk of retirement electing resource specific FRR: 2021/2022 RPM Base Residual Auction

Scenario 2

LDA	Base Residual Auction	FRR for Units at Risk of Retirement			
	Clearing Price ($ per MW-Day)	Clearing Price ($ per MW-Day)	Change ($ per MW-Day)	Change Percent	FRR Capacity (UCAP MW)
RTO	$140.00	$70.00	($70.00)	(50.0%)	23,741.1
ATSI	$171.33	$70.00	($101.33)	(59.1%)	
ComEd	$195.55	$189.02	($6.53)	(3.3%)	
EMAAC	$165.73	$165.47	($0.26)	(0.2%)	
PSEG	$204.29	$203.53	($0.76)	(0.4%)	
BGE	$200.30	$70.00	($130.30)	(65.1%)	
DEOK	$140.00	$128.47	($11.53)	(8.2%)	

Impact of FRR for Annual Wind and Solar Resources

Table 4 shows the results of the 2021/2022 RPM Base Residual Auction if annual wind and solar units, not including summer or winter seasonal generation, had elected the resource specific FRR option. In the 2021/2022 Base Residual Auction, annual wind and solar resources accounted for 1,257.1 MW of offered capacity. In the 2021/2022 RPM Base

deactivation process or requested deactivation are excluded from the at risk analysis. Nuclear plants at risk are defined to be plants that will not cover avoidable costs based on forward prices. For nuclear plants, avoidable costs consist of NEI operating costs, and capital expenditures. See the 2017 State of the Market Report for PJM, Section 7: Net Revenue.

Residual Auction, the import constraints for ComEd, ATSI, EMAAC, PSEG and BGE were binding. The results of the sensitivity show that the ComEd, EMAAC, ATSI, PSEG and BGE import constraints would have remained binding.

The RTO clearing price would have remained the same at $140.00 per MW-day. The ATSI clearing price would have remained the same at $171.33 per MW-day. The ComEd clearing price would have decreased by $2.50 per MW-day to $193.05 per MW-day. The EMAAC clearing price would remained the same at $165.73 per MW-day. The PSEG clearing price would have decreased by $0.40 per MW-day to $203.89 per MW-day. The BGE clearing price would have remained the same at $200.30 per MW-day.

Table 4 Impact of annual wind and solar units electing resource specific FRR: 2021/2022 RPM Base Residual Auction

Scenario 3

LDA	Base Residual Auction Clearing Price ($ per MW-Day)	FRR for Annual Wind and Solar Units Clearing Price ($ per MW-Day)	Change ($ per MW-Day)	Change Percent	FRR Capacity (UCAP MW)
RTO	$140.00	$140.00	$0.00	0.0%	1,257.1
ATSI	$171.33	$171.33	$0.00	0.0%	
ComEd	$195.55	$193.05	($2.50)	(1.3%)	
EMAAC	$165.73	$165.73	$0.00	0.0%	
PSEG	$204.29	$203.89	($0.40)	(0.2%)	
BGE	$200.30	$200.30	$0.00	0.0%	

Impact of FRR for 25 percent of Coal and Nuclear Resource MW

Table 5 shows the results of the 2021/2022 RPM Base Residual Auction if 25 percent of coal and nuclear resource MW had elected the resource specific FRR option. In the 2021/2022 Base Residual Auction, coal and nuclear resources accounted for 75,496.2 MW of offered capacity. Thus, 25 percent of coal and nuclear resource MW are 18,866.3 MW.[10] In the 2021/2022 RPM Base Residual Auction, the import constraints for ATSI, ComEd, EMAAC, PSEG and BGE were binding. The results of the sensitivity show that the ATSI, ComEd, EMAAC, PSEG and BGE import constraints would have remained binding and the DEOK import constraint would have been binding.

The RTO clearing price would have decreased by $39.79 per MW-day to $100.21 per MW-day. The ATSI clearing price would have decreased by $25.65 per MW-day to $145.68 per MW-day. The ComEd clearing price would have decreased by $31.33 per MW-day to $164.22 per MW-day. The EMAAC clearing price would have remained the

10 This result reflects rounding at the offer segment level.

same at $165.73 per MW-day. The PSEG clearing price would have remained the same at $204.29 per MW-day. The BGE clearing price would have decreased by $39.53 per MW-day to $160.77 per MW-day. The DEOK clearing price would have decreased by $22.75 per MW-day to $117.25 per MW-day.

Table 5 Impact of 25 percent of coal and nuclear resource MW electing resource specific FRR: 2021/2022 RPM Base Residual Auction

Scenario 4

LDA	Base Residual Auction	FRR for 25 percent of Coal and Nuclear Resource MW			
	Clearing Price ($ per MW-Day)	Clearing Price ($ per MW-Day)	Change ($ per MW-Day)	Change Percent	FRR Capacity (UCAP MW)
RTO	$140.00	$100.21	($39.79)	(28.4%)	18,866.3
ATSI	$171.33	$145.68	($25.65)	(15.0%)	
ComEd	$195.55	$164.22	($31.33)	(16.0%)	
EMAAC	$165.73	$165.73	$0.00	0.0%	
PSEG	$204.29	$204.29	$0.00	0.0%	
BGE	$200.30	$160.77	($39.53)	(19.7%)	
DEOK	$140.00	$117.25	($22.75)	(16.3%)	

Impact of FRR for 50 percent of Coal and Nuclear Resource MW

Table 6 shows the results of the 2021/2022 RPM Base Residual Auction if 50 percent of coal and nuclear resource MW had elected the resource specific FRR option. In the 2021/2022 Base Residual Auction, coal and nuclear resources accounted for 75,496.2 MW of offered capacity. Thus, 50 percent of coal and nuclear resource MW are 37,732.7 MW. In the 2021/2022 RPM Base Residual Auction, the import constraints for ATSI, ComEd, EMAAC, PSEG and BGE were binding. The results of the sensitivity show that the ComEd, EMAAC, PSEG and BGE import constraints would have remained binding, ATSI import constraint would not have been binding and the DEOK import constraint would have been binding.

The RTO clearing price would have decreased by $70.04 per MW-day to $69.96 per MW-day. The ATSI clearing price would have decreased by $101.37 per MW-day to $69.96 per MW-day. The ComEd clearing price would have decreased by $116.86 per MW-day to $78.69 per MW-day. The EMAAC clearing price would have decreased by $15.81 per MW-day to $149.92 per MW-day. The PSEG clearing price would have remained the same at $204.29 per MW-day. The BGE clearing price would have decreased by $40.53 per MW-day to $159.77 per MW-day. The DEOK clearing price would have decreased by $54.01 per MW-day to $85.99 per MW-day.

Table 6 Impact of 50 percent of coal and nuclear resource MW electing resource specific FRR: 2021/2022 RPM Base Residual Auction

Scenario 5

LDA	Base Residual Auction Clearing Price ($ per MW-Day)	FRR for 50 percent of Coal and Nuclear Resource MW Clearing Price ($ per MW-Day)	Change ($ per MW-Day)	Change Percent Percent	FRR Capacity (UCAP MW)
RTO	$140.00	$69.96	($70.04)	(50.0%)	37,732.7
ATSI	$171.33	$69.96	($101.37)	(59.2%)	
ComEd	$195.55	$78.69	($116.86)	(59.8%)	
EMAAC	$165.73	$149.92	($15.81)	(9.5%)	
PSEG	$204.29	$204.29	$0.00	0.0%	
BGE	$200.30	$159.77	($40.53)	(20.2%)	
DEOK	$140.00	$85.99	($54.01)	(38.6%)	

Impact of FRR for 100 percent of Coal and Nuclear Resource MW

Table 7 shows the results of the 2021/2022 RPM Base Residual Auction if 100 percent of coal and nuclear resource MW had elected the resource specific FRR option. In the 2021/2022 Base Residual Auction, coal and nuclear resources accounted for 75,496.2 MW of offered capacity. In the 2021/2022 RPM Base Residual Auction, the import constraints for ATSI, ComEd, EMAAC, PSEG and BGE were binding. The results of the sensitivity show that the ComEd and PSEG import constraints would have remained binding, ATSI, EMAAC and BGE import constraints would not have been binding and the MAAC import constraint would have been binding.

The RTO clearing price would have decreased by $115.00 per MW-day to $25.00 per MW-day. The ATSI clearing price would have decreased by $146.33 per MW-day to $25.00 per MW-day. The ComEd clearing price would have decreased by $151.62 per MW-day to $43.93 per MW-day. The MAAC clearing price would have increased by $10.92 per MW-day to $150.92 per MW-day. The EMAAC clearing price would have decreased by $14.81 per MW-day to $150.92 per MW-day. The PSEG clearing price would have decreased by $2.11 per MW-day to $202.18 per MW-day. The BGE clearing price would have decreased by $49.38 per MW-day to $150.92 per MW-day.

Table 7 Impact of 100 percent of coal and nuclear resource MW electing resource specific FRR: 2021/2022 RPM Base Residual Auction

Scenario 6

LDA	Base Residual Auction Clearing Price ($ per MW-Day)	FRR for 100 percent of Coal and Nuclear Resource MW Clearing Price ($ per MW-Day)	Change ($ per MW-Day)	Change Percent	FRR Capacity (UCAP MW)
RTO	$140.00	$25.00	($115.00)	(82.1%)	75,496.2
ATSI	$171.33	$25.00	($146.33)	(85.4%)	
ComEd	$195.55	$43.93	($151.62)	(77.5%)	
MAAC	$140.00	$150.92	$10.92	7.8%	
EMAAC	$165.73	$150.92	($14.81)	(8.9%)	
PSEG	$204.29	$202.18	($2.11)	(1.0%)	
BGE	$200.30	$150.92	($49.38)	(24.7%)	

Impact of FRR for 2,000 MW of Extra Marginal Resources

In order to show the impacts of the selection of the resource specific FRR option by smaller MW levels of extra marginal resources, sensitivities were run at a range of MW levels: 2,000 MW; 4,000 MW; 6,000 MW; 8,000 MW; 10,000 MW; and 12,000 MW. The MW levels of extra marginal resources are assigned to LDAs based on each LDA’s share of the reliability requirement.

Table 8 shows the results of the 2021/2022 RPM Base Residual Auction if 2,000 MW of resources that did not clear the 2021/2022 Base Residual Auction had elected the resource specific FRR option. In the 2021/2022 RPM Base Residual Auction, the import constraints for ATSI, ComEd, EMAAC, PSEG and BGE were binding. The results of the sensitivity show that the ATSI, ComEd, EMAAC, PSEG and BGE import constraints would have remained binding and the DEOK import constraint would have been binding.

The RTO clearing price would have decreased by $18.79 per MW-day to $121.21 per MW-day. The ATSI clearing price would have decreased by $26.33 per MW-day to $145.00 per MW-day. The ComEd clearing price would have decreased by $6.55 per MW-day to $189.00 per MW-day. The EMAAC clearing price would have decreased by $0.73 per MW-day to $165.00 per MW-day. The PSEG clearing price would have decreased by $19.12 per MW-day to $185.17 per MW-day. The BGE clearing price would have decreased by $19.80 per MW-day to $180.50 per MW-day. The DEOK clearing price would have decreased by $11.53 per MW-day to $128.47 per MW-day.

Table 8 Impact of 2,000 MW of extra marginal resources electing resource specific FRR: 2021/2022 RPM Base Residual Auction

Scenario 7

LDA	Base Residual Auction Clearing Price ($ per MW-Day)	FRR for 2,000 MW Extra Marginal Supply Clearing Price ($ per MW-Day)	Change ($ per MW-Day)	Change Percent	FRR Capacity (UCAP MW)
RTO	$140.00	$121.21	($18.79)	(13.4%)	2,000.0
ATSI	$171.33	$145.00	($26.33)	(15.4%)	
ComEd	$195.55	$189.00	($6.55)	(3.3%)	
EMAAC	$165.73	$165.00	($0.73)	(0.4%)	
PSEG	$204.29	$185.17	($19.12)	(9.4%)	
BGE	$200.30	$180.50	($19.80)	(9.9%)	
DEOK	$140.00	$128.47	($11.53)	(8.2%)	

Impact of FRR for 4,000 MW of Extra Marginal Resources

Table 9 shows the results of the 2021/2022 RPM Base Residual Auction if 4,000 MW of resources that did not clear the 2021/2022 Base Residual Auction had elected the resource specific FRR option. In the 2021/2022 RPM Base Residual Auction, the import constraints for ATSI, ComEd, EMAAC, PSEG and BGE were binding. The results of the sensitivity show that the ATSI, ComEd, EMAAC, PSEG and BGE import constraints would have remained binding and the DEOK import constraint would have been binding.

The RTO clearing price would have decreased by $32.80 per MW-day to $107.20 per MW-day. The ATSI clearing price would have decreased by $26.33 per MW-day to $145.00 per MW-day. The ComEd clearing price would have decreased by $6.45 per MW-day to $189.10 per MW-day. The EMAAC clearing price would have decreased by $1.22 per MW-day to $164.51 per MW-day. The PSEG clearing price would have decreased by $38.21 per MW-day to $166.08 per MW-day. The BGE clearing price would have decreased by $19.80 per MW-day to $180.50 per MW-day. The DEOK clearing price would have decreased by $17.07 per MW-day to $122.93 per MW-day.

Table 9 Impact of 4,000 MW of extra marginal resources electing resource specific FRR: 2021/2022 RPM Base Residual Auction

Scenario 8

LDA	Base Residual Auction Clearing Price ($ per MW-Day)	FRR for 4,000 MW Extra Marginal Supply Clearing Price ($ per MW-Day)	Change ($ per MW-Day)	Change Percent	FRR Capacity (UCAP MW)
RTO	$140.00	$107.20	($32.80)	(23.4%)	4,000.0
ATSI	$171.33	$145.00	($26.33)	(15.4%)	
ComEd	$195.55	$189.10	($6.45)	(3.3%)	
EMAAC	$165.73	$164.51	($1.22)	(0.7%)	
PSEG	$204.29	$166.08	($38.21)	(18.7%)	
BGE	$200.30	$180.50	($19.80)	(9.9%)	
DEOK	$140.00	$122.93	($17.07)	(12.2%)	

Impact of FRR for 6,000 MW of Extra Marginal Resources

Table 10 shows the results of the 2021/2022 RPM Base Residual Auction if 6,000 MW of resources that did not clear the 2021/2022 Base Residual Auction had elected the resource specific FRR option. In the 2021/2022 RPM Base Residual Auction, the import constraints for ATSI, ComEd, EMAAC, PSEG and BGE were binding. The results of the sensitivity show that the ATSI, ComEd, EMAAC, PSEG and BGE import constraints would have remained binding and the DEOK import constraint would have been binding.

The RTO clearing price would have decreased by $46.50 per MW-day to $93.50 per MW-day. The ATSI clearing price would have decreased by $26.33 per MW-day to $145.00 per MW-day. The ComEd clearing price would have increased by $3.55 per MW-day to $199.10 per MW-day. The EMAAC clearing price would have decreased by $9.27 per MW-day to $156.46 per MW-day. The PSEG clearing price would have decreased by $39.12 per MW-day to $165.17 per MW-day. The BGE clearing price would have decreased by $39.53 per MW-day to $160.77 per MW-day. The DEOK clearing price would have decreased by $22.75 per MW-day to $117.25 per MW-day.

Table 10 Impact of 6,000 MW of extra marginal resources electing resource specific FRR: 2021/2022 RPM Base Residual Auction

Scenario 9

LDA	Base Residual Auction Clearing Price ($ per MW-Day)	FRR for 6,000 MW Extra Marginal Supply Clearing Price ($ per MW-Day)	Change ($ per MW-Day)	Change Percent	FRR Capacity (UCAP MW)
RTO	$140.00	$93.50	($46.50)	(33.2%)	6,000.0
ATSI	$171.33	$145.00	($26.33)	(15.4%)	
ComEd	$195.55	$199.10	$3.55	1.8%	
EMAAC	$165.73	$156.46	($9.27)	(5.6%)	
PSEG	$204.29	$165.17	($39.12)	(19.1%)	
BGE	$200.30	$160.77	($39.53)	(19.7%)	
DEOK	$140.00	$117.25	($22.75)	(16.3%)	

Impact of FRR for 8,000 MW of Extra Marginal Resources

Table 11 shows the results of the 2021/2022 RPM Base Residual Auction if 8,000 MW of resources that did not clear the 2021/2022 Base Residual Auction had elected the resource specific FRR option. In the 2021/2022 RPM Base Residual Auction, the import constraints for ATSI, ComEd, EMAAC, PSEG and BGE were binding. The results of the sensitivity show that the ATSI, ComEd, EMAAC, PSEG and BGE import constraints would have remained binding and the DEOK import constraint would have been binding.

The RTO clearing price would have decreased by $55.23 per MW-day to $84.77 per MW-day. The ATSI clearing price would have increased by $124.67 per MW-day to $296.00 per MW-day. The ComEd clearing price would have decreased by $1.09 per MW-day to $194.46 per MW-day. The EMAAC clearing price would have decreased by $20.73 per MW-day to $145.00 per MW-day. The PSEG clearing price would have decreased by $44.13 per MW-day to $160.16 per MW-day. The BGE clearing price would have decreased by $39.53 per MW-day to $160.77 per MW-day. The DEOK clearing price would have decreased by $32.77 per MW-day to $107.23 per MW-day.

Table 11 Impact of 8,000 MW of extra marginal resources electing resource specific FRR: 2021/2022 RPM Base Residual Auction

Scenario 10

LDA	Base Residual Auction Clearing Price ($ per MW-Day)	FRR for 8,000 MW Extra Marginal Supply Clearing Price ($ per MW-Day)	Change ($ per MW-Day)	Change Percent	FRR Capacity (UCAP MW)
RTO	$140.00	$84.77	($55.23)	(39.5%)	8,000.0
ATSI	$171.33	$296.00	$124.67	72.8%	
ComEd	$195.55	$194.46	($1.09)	(0.6%)	
EMAAC	$165.73	$145.00	($20.73)	(12.5%)	
PSEG	$204.29	$160.16	($44.13)	(21.6%)	
BGE	$200.30	$160.77	($39.53)	(19.7%)	
DEOK	$140.00	$107.23	($32.77)	(23.4%)	

Impact of FRR for 10,000 MW of Extra Marginal Resources

Table 12 shows the results of the 2021/2022 RPM Base Residual Auction if 10,000 MW of resources that did not clear the 2021/2022 Base Residual Auction had elected the resource specific FRR option. In the 2021/2022 RPM Base Residual Auction, the import constraints for ATSI, ComEd, EMAAC, PSEG and BGE were binding. The results of the sensitivity show that the ATSI, ComEd, EMAAC, PSEG and BGE import constraints would have remained binding and the DEOK import constraint would have been binding.

The RTO clearing price would have decreased by $61.56 per MW-day to $78.44 per MW-day. The ATSI clearing price would have increased by $44.65 per MW-day to $215.98 per MW-day. The ComEd clearing price would have decreased by $8.87 per MW-day to $186.68 per MW-day. The EMAAC clearing price would have decreased by $29.68 per MW-day to $136.05 per MW-day. The PSEG clearing price would have decreased by $50.06 per MW-day to $154.23 per MW-day. The BGE clearing price would have decreased by $19.80 per MW-day to $180.50 per MW-day. The DEOK clearing price would have decreased by $36.87 per MW-day to $103.13 per MW-day.

Table 12 Impact of 10,000 MW of extra marginal resources electing resource specific FRR: 2021/2022 RPM Base Residual Auction

Scenario 11

LDA	Base Residual Auction Clearing Price ($ per MW-Day)	FRR for 10,000 MW Extra Marginal Supply Clearing Price ($ per MW-Day)	Change ($ per MW-Day)	Change Percent	FRR Capacity (UCAP MW)
RTO	$140.00	$78.44	($61.56)	(44.0%)	10,000.0
ATSI	$171.33	$215.98	$44.65	26.1%	
ComEd	$195.55	$186.68	($8.87)	(4.5%)	
EMAAC	$165.73	$136.05	($29.68)	(17.9%)	
PSEG	$204.29	$154.23	($50.06)	(24.5%)	
BGE	$200.30	$180.50	($19.80)	(9.9%)	
DEOK	$140.00	$103.13	($36.87)	(26.3%)	

Impact of FRR for 12,000 MW of Extra Marginal Resources

Table 13 shows the results of the 2021/2022 RPM Base Residual Auction if 12,000 MW of resources that did not clear the 2021/2022 Base Residual Auction had elected the resource specific FRR option. In the 2021/2022 RPM Base Residual Auction, the import constraints for ATSI, ComEd, EMAAC, PSEG and BGE were binding. The results of the sensitivity show that the ATSI, ComEd, EMAAC, PSEG and BGE import constraints would have remained binding and the DEOK import constraint would have been binding.

The RTO clearing price would have decreased by $70.02 per MW-day to $69.98 per MW-day. The ATSI clearing price would have increased by $19.84 per MW-day to $191.17 per MW-day. The ComEd clearing price would have decreased by $47.46 per MW-day to $148.09 per MW-day. The EMAAC clearing price would have decreased by $30.68 per MW-day to $135.05 per MW-day. The PSEG clearing price would have decreased by $67.78 per MW-day to $136.51 per MW-day. The BGE clearing price would have decreased by $19.80 per MW-day to $180.50 per MW-day. The DEOK clearing price would have decreased by $40.70 per MW-day to $99.30 per MW-day.

Table 13 Impact of 12,000 MW of extra marginal resources electing resource specific FRR: 2021/2022 RPM Base Residual Auction

Scenario 12

LDA	Base Residual Auction Clearing Price ($ per MW-Day)	FRR for 12,000 MW Extra Marginal Supply Clearing Price ($ per MW-Day)	Change ($ per MW-Day)	Change Percent	FRR Capacity (UCAP MW)
RTO	$140.00	$69.98	($70.02)	(50.0%)	12,000.0
ATSI	$171.33	$191.17	$19.84	11.6%	
ComEd	$195.55	$148.09	($47.46)	(24.3%)	
EMAAC	$165.73	$135.05	($30.68)	(18.5%)	
PSEG	$204.29	$136.51	($67.78)	(33.2%)	
BGE	$200.30	$180.50	($19.80)	(9.9%)	
DEOK	$140.00	$99.30	($40.70)	(29.1%)	

Impact of FRR for Units at Risk of Retirement under PJM's Proposed Repricing Two Stage Auction Method

Table 14 shows the results of the 2021/2022 RPM Base Residual Auction if units at risk of retirement had elected the resource specific FRR option under the PJM's proposed Repricing Method using two stage auction clearing. In the 2021/2022 Base Residual Auction, units at risk of retirement accounted for 23,741.1 MW of offered capacity.

PJM proposed to clear the auction in two stages.[11] In the first stage, all subsidized resources would be entered into the auction at $0 per MW-day. In the second stage, the auction would be cleared after removing the offers of the subsidized resources. The reliability requirement, VRR curves and capacity import limits of every LDA would be kept the same in both stages of the auction clearing. The clearing quantities would be obtained from the solution of the first stage auction. The clearing prices would be set by the second stage of the auction clearing. Any capacity that cleared only in the second stage of auction clearing would be paid a lost opportunity cost in $ per MW-day equal to the difference between the clearing price and offered price, but would not be treated as cleared capacity resources and would not take on any performance obligations.

11 See Meeting Materials for the Markets and Reliability Committee Special Session: PJM Response to FERC on Capacity Market Reforms, "PJM Proposal including Stakeholder Input", September 11, 2018, <https://www.pjm.com/-/media/committees-groups/committees/mrc/20180911-special/20180911-pjm-proposal-including-stakeholder-input.ashx>.

In the 2021/2022 RPM Base Residual Auction, the import constraints for ATSI, ComEd, EMAAC, PSEG and BGE were binding. The results of the sensitivity show that ATSI, ComEd, EMAAC, PSEG and BGE imports constraints would not have been binding and that the MAAC import limit would have been binding. The RTO clearing price would have increased by $94.67 per MW-day to $234.67 per MW-day. The ATSI clearing price would have increased by $63.34 per MW-day to $234.67 per MW-day. The ComEd clearing price would have increased by $39.12 per MW-day to $234.67 per MW-day. The EMAAC clearing price would have increased by $273.31 per MW-day to $439.04 per MW-day. The PSEG clearing price would have increased by $238.75 per MW-day to $439.04 per MW-day. The BGE clearing price would have increased by $238.74 per MW-day to $439.04 per MW-day.

Table 15 shows the impact on the total revenue of the 2021/2022 RPM Base Residual Auction if units at risk of retirement had elected the resource specific FRR option, and the auction were cleared under the market method and PJM's proposed repricing method. The market method is the method used in the first 12 scenarios. Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2021/2022 RPM Base Residual Auction were $9,300,877,106.

If units at risk of retirement elected the resource specific FRR, the auction were cleared under the PJM's proposed repricing method and everything else remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual Auction would have been $16,243.440,563. With the estimated cost of subsidies at $846,884,670, and lost opportunity costs at $651,898,639, the total revenues would have been $17,742,223,873, an increase of $8,441,346,767 or 90.8 percent, compared to the actual results.[12]

If units at risk of retirement elected the resource specific FRR, the auction were cleared under the market method (Scenario 2) and everything else remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual Auction would have been $5,536,178,745. With the estimated cost of subsidies at $846,884,670, the total revenues would have been $6,383,063,415, a decrease of $2,917,813,691 or 31.4 percent, compared to the actual results.

[12] The subsidy for a nuclear unit is equal to net avoidable costs. This is the amount of payment such units would need in order to continue operating in addition to revenues from the energy and ancillary services markets. Actual subsidy payments could exceed this amount. For nuclear units, avoidable costs consist of NEI operating costs and incremental capital expenditures. For non-nuclear units, the subsidy is equal to the unit's offer price in the 2021/2022 RPM Base Residual Action. This is what such units would need in order to continue operating.

Under PJM's proposed two stage auction method, clearing prices would be determined in the second stage of auction clearing, where the subsidized resources are removed from the supply while the VRR requirements are left unchanged. This approach resulted in clearing additional high priced offers in order to meet the same demand with reduced MW of supply. In some LDAs, removal of subsidized resources meant there was not enough supply to intersect the sloped portion of the VRR curve resulting in clearing prices set at the maximum price, or 1.5 times the net CONE of the LDA. Under PJM's proposed clearing method, the additional capacity which only cleared in the second stage of the auction would be paid lost opportunity cost. These resources would not take on any capacity performance obligations despite setting clearing prices and despite being paid the clearing price.

Table 14 Impact of units at risk of retirement electing resource specific FRR under PJM's proposed method: 2021/2022 RPM Base Residual Auction

Scenario 13

LDA	Base Residual Auction Clearing Price ($ per MW-Day)	FRR for Units at Risk of Retirement (PJM's Repricing Method) Clearing Price ($ per MW-Day)	Change ($ per MW-Day)	Change Percent	FRR Capacity (UCAP MW)
RTO	$140.00	$234.67	$94.67	67.6%	23,741.1
ATSI	$171.33	$234.67	$63.34	37.0%	
ComEd	$195.55	$234.67	$39.12	20.0%	
MAAC	$140.00	$439.04	$299.04	213.6%	
EMAAC	$165.73	$439.04	$273.31	164.9%	
PSEG	$204.29	$439.04	$234.75	114.9%	
BGE	$200.30	$439.04	$238.74	119.2%	

Table 15 Change in auction revenue due to units at risk of retirement electing resource specific FRR under PJM's proposed method: 2021/2022 RPM Base Residual Auction

	$ per Delivery Year		
	Actual Results	Market Method	PJM Repricing Method
Cleared resource revenue	$9,299,504,396	$5,536,067,785	$16,243,440,563
Makewhole revenue	$1,372,710	$110,960	
Estimated cost of subsidies		$846,884,670	$846,884,670
Lost opportunity cost			$651,898,639
Total capacity revenue	$9,300,877,106	$6,383,063,415	$17,742,223,873

Impact of FRR for Units at High Risk of Retirement under PJM's Proposed Repricing Two Stage Auction Method

Table 16 shows the results of the 2021/2022 RPM Base Residual Auction if units at high risk of retirement had elected the resource specific FRR option under the PJM's proposed Repricing Method using two stage auction clearing. In the 2021/2022 Base

Residual Auction, units at high risk of retirement accounted for 11,777.2 MW of offered capacity.[13]

In the 2021/2022 RPM Base Residual Auction, the import constraints for ATSI, ComEd, EMAAC, PSEG and BGE were binding. The results of the sensitivity show that ATSI, ComEd, and PSEG would have remained binding and EMAAC and BGE import limits would not have been binding. The RTO clearing price would have increased by $40.62 per MW-day to $180.62 per MW-day. The ATSI clearing price would have increased by $28.66 per MW-day to $199.99 per MW-day. The ComEd clearing price would have increased by $4.43 per MW-day to $199.98 per MW-day. The EMAAC clearing price would have increased by $14.89 per MW-day to $180.62 per MW-day. The PSEG clearing price would have remained the same at $204.29 per MW-day. The BGE clearing price would have decreased by $19.68 per MW-day to $180.62 per MW-day.

Table 17 shows the impact on the total revenue of the 2021/2022 RPM Base Residual Auction if units at high risk of retirement had elected the resource specific FRR option, and the auction were cleared under the market method and PJM's proposed repricing method. Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2021/2022 RPM Base Residual Auction were $9,300,877,106.

If units at high risk of retirement elected resource specific FRR, the auction were cleared under the PJM's proposed repricing method and everything else remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual Auction would have been $10,335,363,667. With the estimated cost of subsidies at $497,957,568, and lost opportunity costs at $86,546,795 the total revenues would have been $10,919,868,029 an increase of $1,618,990,923 or 17.4 percent, compared to the actual results.

If units at high risk of retirement elected resource specific FRR, the auction were cleared under the market method and everything else remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual Auction would have been $6,693,643,385. With the estimated cost of subsidies at $497,957,568, the total revenues would have been $7,191,600,953, a decrease of $2,109,276,153 or 22.7 percent, compared to the actual results.

[13] Resources at risk of retirement were ranked by the percent of ACR recovered through the energy and capacity markets. For this analysis, the resources at high risk of retirement consist of the 50 percent of resources at risk of retirement with the lowest percent of ACR recovered in the markets.

Table 16 Impact of units at high risk of retirement electing resource specific FRR under PJM's proposed method: 2021/2022 RPM Base Residual Auction

Scenario 14

LDA	Base Residual Auction Clearing Price ($ per MW-Day)	FRR for Units at High Risk of Retirement (PJM's Repricing Method) Clearing Price ($ per MW-Day)	Change ($ per MW-Day)	Change Percent	FRR Capacity (UCAP MW)
RTO	$140.00	$180.62	$40.62	29.0%	11,777.2
ATSI	$171.33	$199.99	$28.66	16.7%	
ComEd	$195.55	$199.98	$4.43	2.3%	
EMAAC	$165.73	$180.62	$14.89	9.0%	
PSEG	$204.29	$204.29	$0.00	0.0%	
BGE	$200.30	$180.62	($19.68)	(9.8%)	

Table 17 Change in auction revenue due to units at high risk of retirement electing resource specific FRR under PJM's proposed method: 2021/2022 RPM Base Residual Auction

	$ per Delivery Year		
	Actual Results	Market Method	PJM Repricing Method
Cleared resource revenue	$9,299,504,396	$6,687,813,605	$10,334,838,073
Makewhole revenue	$1,372,710	$5,829,780	$525,593
Estimated cost of subsidies		$497,957,568	$497,957,568
Lost opportunity cost			$86,546,795
Total capacity revenue	$9,300,877,106	$7,191,600,953	$10,919,868,029

Attachment

This attachment illustrates the clearing of the Base Residual Auction with a simple example under two scenarios: the subsidized resource was extra marginal in the actual auction and the subsidized resource was infra marginal in the actual auction.

The example capacity market is divided into two locational deliverable areas (LDA): child LDA and parent LDA. Table A 1 shows the assumed parameters for the derivation of the VRR curve.

The X coordinates of the VRR curve are derived using the following formula.[14]

$For\ i \in \{a, b, c\}$

$$X_i = Reliability\ Requirement \times \left(\frac{1 + IRM + Factor_i}{1 + IRM}\right)$$

where

$$Reliability\ Requirement = Peak\ Load\ Forecast * FPR$$

$FPR = Forecast\ Pool\ Requirement = (1 + IRM) * (1 - Pool\ Wide\ EFORd)$

$$IRM = Installed\ Reserve\ Margin\ as\ a\ percentage$$

$Factor_i = percentage\ shift\ of\ coordinate\ i$

Figure A 1 and Figure A 2 show the variable resource requirement (VRR) curves for child and parent LDAs. Table A 2 shows the capacity offers for child LDA and Table A 3 shows the capacity offers for the parent LDA. The capacity emergency transfer limit (CETL) between parent LDA and child LDA is assumed as 150 MW.

Base Case: No Subsidies

Figure A 3 shows the clearing of the child LDA. Figure A 4 shows the clearing of the parent LDA. The capacity imports to the child LDA were constrained by CETL resulting in the child LDA price separating from the parent LDA.[15] The clearing price for the child LDA was $65 per MW-day. The clearing price for the parent LDA was $55 per MW-day.

[14] "PJM Manual 18: PJM Capacity Market," Rev. 40 (Feb. 22, 2018) at 39.

[15] For details on the clearing algorithm used for Base Residual Auction, see "Analysis of the 2021/2022 RPM Base Residual Auction Revised,"

Scenario 1: Subsidy for Extra Marginal Resource

In this scenario, the extra marginal resource C7, offered for $110 per MW-day, received a subsidy and C7 used the resource specific FRR option. The reliability requirements for the child LDA and the parent LDA were reduced by 200 MW, equal to the unforced capacity of the subsidized resource C7. Table A 4 shows the parameters of the shifted VRR curve. Figure A 5 compares the original VRR curve and the shifted VRR curve. The shifted VRR curve was slightly steeper than the original VRR curve as a result of the definition of the X coordinates.

The results show that when the extra marginal resource was removed together with matching load, the clearing price of the child LDA decreased to $43.63 per MW-day from $65.00 per MW-day in the base case. The clearing price of the parent LDA also decreased to $43.63 per MW-day from $55.00 per MW-day in the base case. The capacity imports to the child LDA were not constrained when the extra marginal resource was removed, which resulted in child LDA not price separating from the parent LDA. The lower clearing prices resulted from the left shift of the VRR curve while the supply curve below the clearing price of the base case remained the same. This example shows that when subsidized resources select the resource specific FRR option, and those resources are extra marginal, the result is to reduce the clearing price for the remaining resources offering competitively in the residual auction.

Scenario 2: Subsidy for Infra Marginal Resource

In this scenario, the infra marginal resource C2, offered for $25 per MW-day, received a subsidy and C2 used the resource specific FRR option. The reliability requirements for the child LDA and parent LDA were reduced by 140 MW, equal to the unforced capacity of the subsidized resource C2. Table A 5 shows the parameters of the shifted VRR curve.

The results show that the clearing price of the child LDA remained the same at $65.00 per MW-day. The clearing price of the parent LDA also remained the same at $55.00 per MW-day. The capacity imports to the child LDA were constrained, which resulted in child LDA price separating from the parent LDA. The clearing prices in the scenario did not change because the removal of the cleared subsidized resource from the supply curve was followed by the left shift of the VRR curve due to the reduction in the reliability requirement. This example shows that subsidizing resources that clear the

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<http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Analysis_of_the_20212022_RPM_BRA_Revised_20180824.pdf> (August 24, 2018).

auction results in same prices or slightly higher prices for the remaining resources offering competitively in the residual auction.[16]

Table A 1 Parameters for VRR curve: Base case[17]

	Child (IRM = 15%, RR = 400 MW UCAP)			Parent (IRM = 15%, RR = 800 MW UCAP)		
	Factors	X (MW UCAP)	Y ($/MW-day)	Factors	X (MW UCAP)	Y ($/MW-day)
a	-17.13%	400.0	170.0	-7.19%	750.0	150.0
b	7.34%	500.0	90.0	7.19%	850.0	100.0
c	80.74%	800.0	0.0	86.25%	1400.0	0.0

[16] In this example, the clearing prices did not change because the flexibly offered marginal resources were same in both the base case and the Scenario 2. However, in general, it is possible for the clearing prices to be slightly higher or equal. This is because of the slight change in the slope of the VRR curve.

[17] The factors used in the example are not same as the factors used by PJM in the Base Residual Auction.

Figure A 1 VRR curve for child LDA

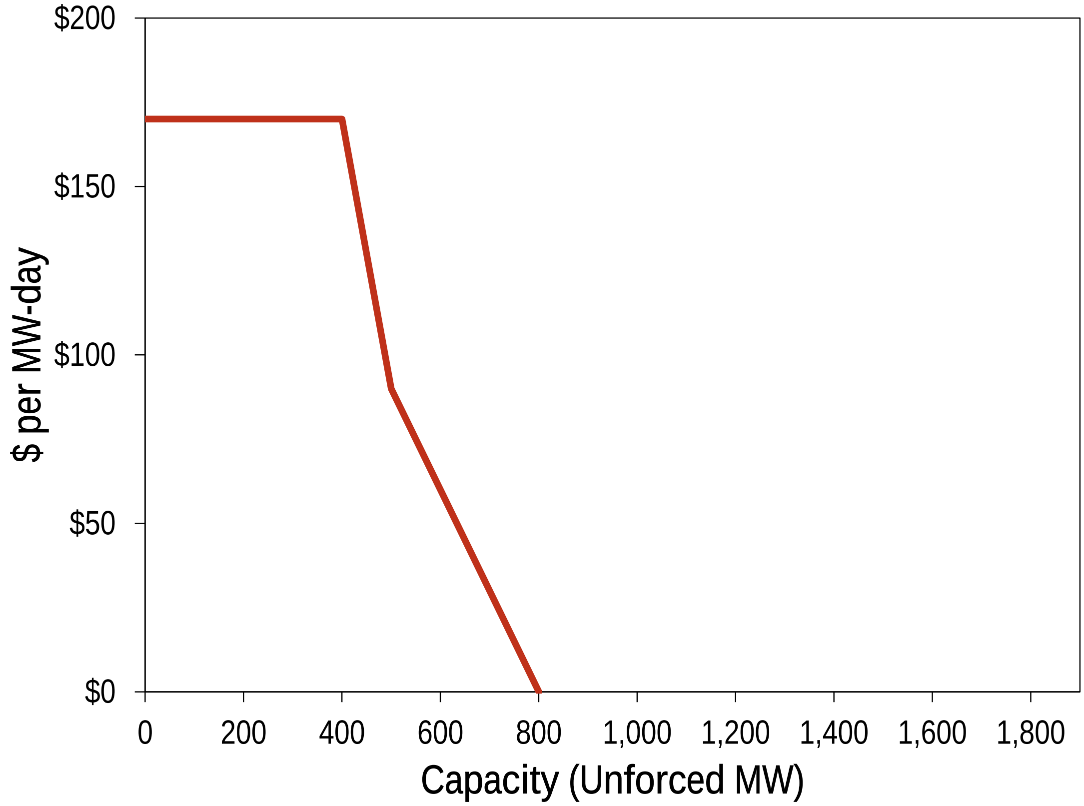

Figure A 2 VRR curve for parent LDA

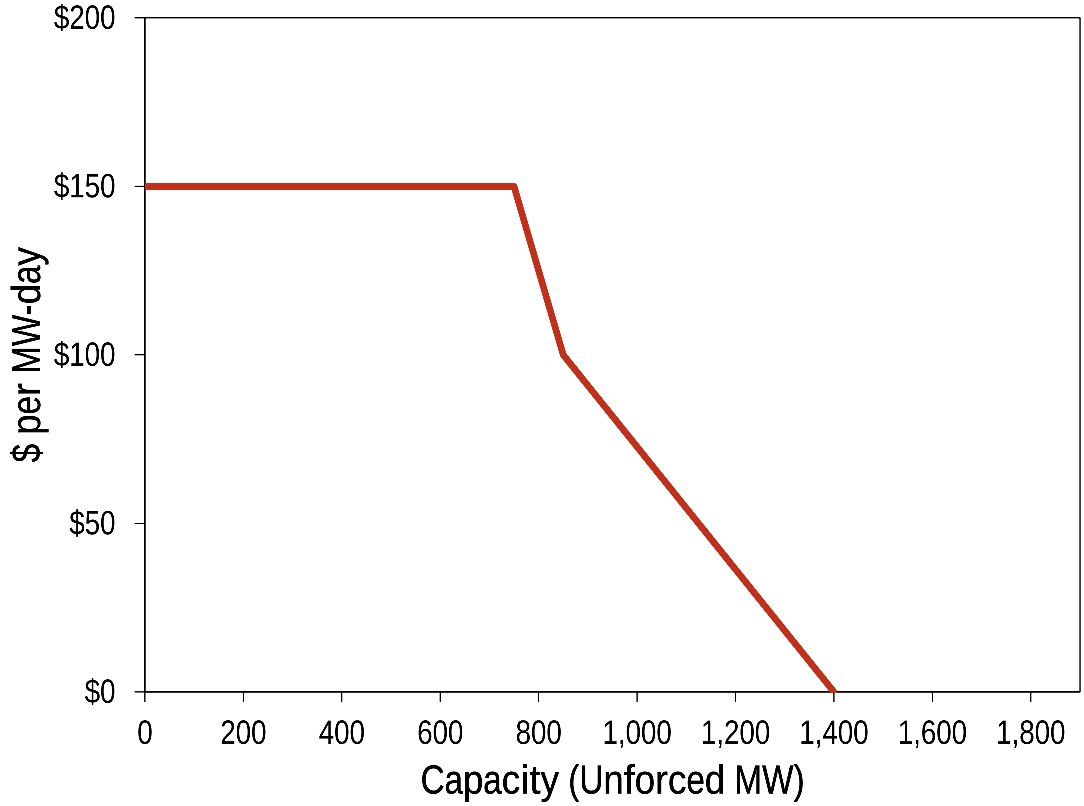

Table A 2 Capacity offers for child LDA

	Capacity (Unforced MW)	Offer ($/MW-day)
Res C1	125.0	$15.00
Res C2	140.0	$25.00
Res C3	110.0	$45.00
Res C4	100.0	$65.00
Res C5	70.0	$72.00
Res C6	125.0	$85.00
Res C7	200.0	$110.00
Res C8	75.0	$140.00

Table A 3 Capacity offers for parent LDA

	Capacity (Unforced MW)	Offer ($/MW-day)
Res P1	150.0	$5.00
Res P2	200.0	$15.00
Res P3	160.0	$30.00
Res P4	95.0	$42.00
Res P5	240.0	$55.00
Res P6	195.0	$65.00
Res P7	110.0	$75.00
Res P8	50.0	$90.00

Figure A 3 Clearing of child LDA: Base case

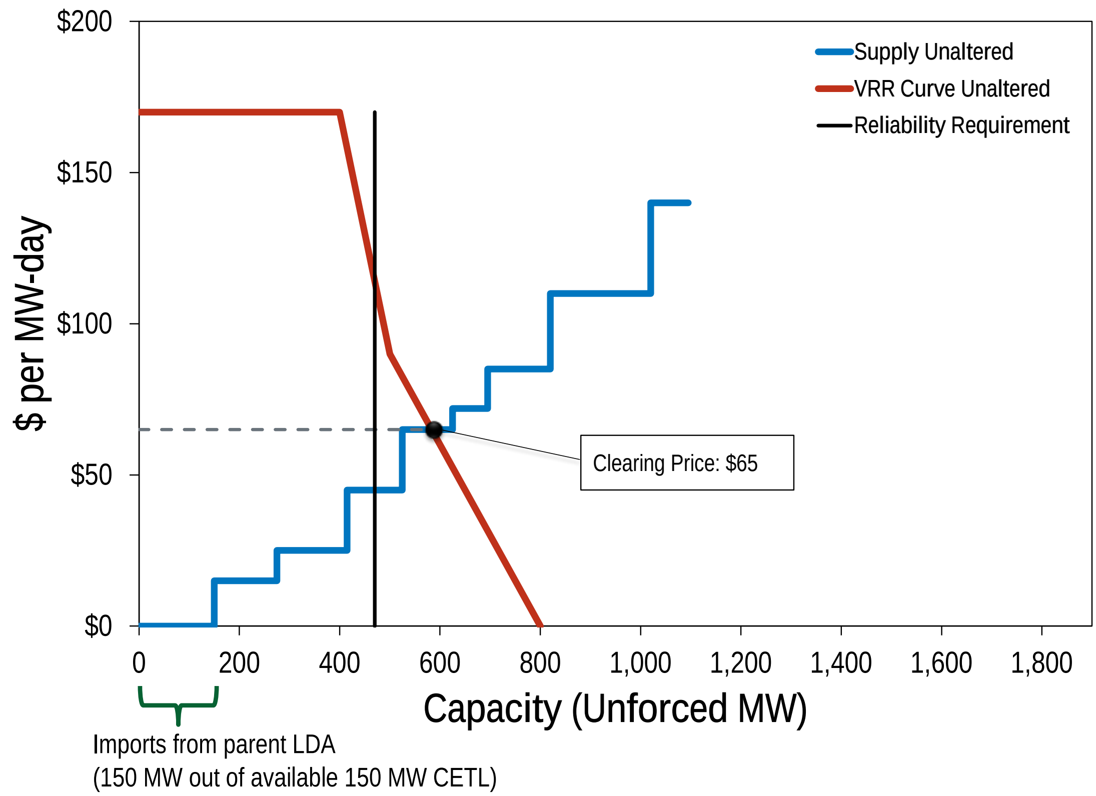

Figure A 4 Clearing of parent LDA: Base case

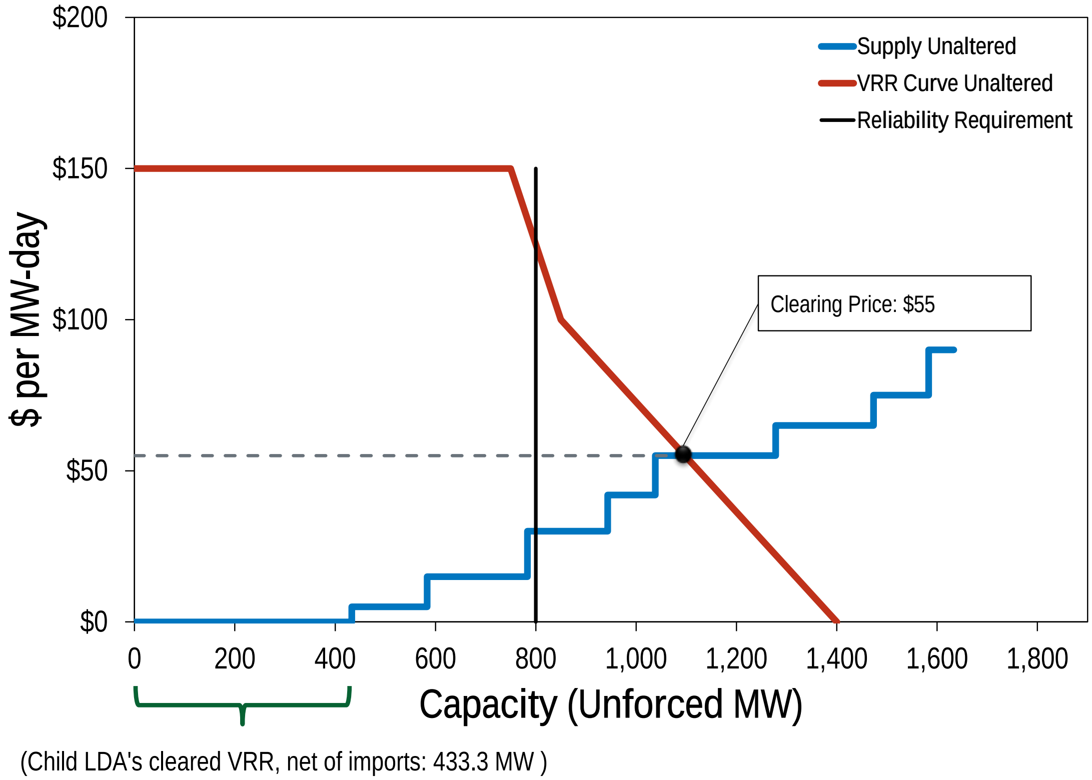

Table A 4 Parameters for VRR curve: Scenario 1

	Child (IRM = 15%, RR = 270 MW UCAP)			Parent (IRM = 15%, RR = 600 MW UCAP)		
	Factors	X (MW UCAP)	Y ($/MW-day)	Factors	X (MW UCAP)	Y ($/MW-day)
a	-17.13%	229.8	170.0	-7.19%	562.5	150.0
b	7.34%	287.2	90.0	7.19%	637.5	100.0
c	80.74%	459.6	0.0	86.25%	1050.0	0.0

Figure A 5 Change in VRR curve of child LDA: Scenario 1

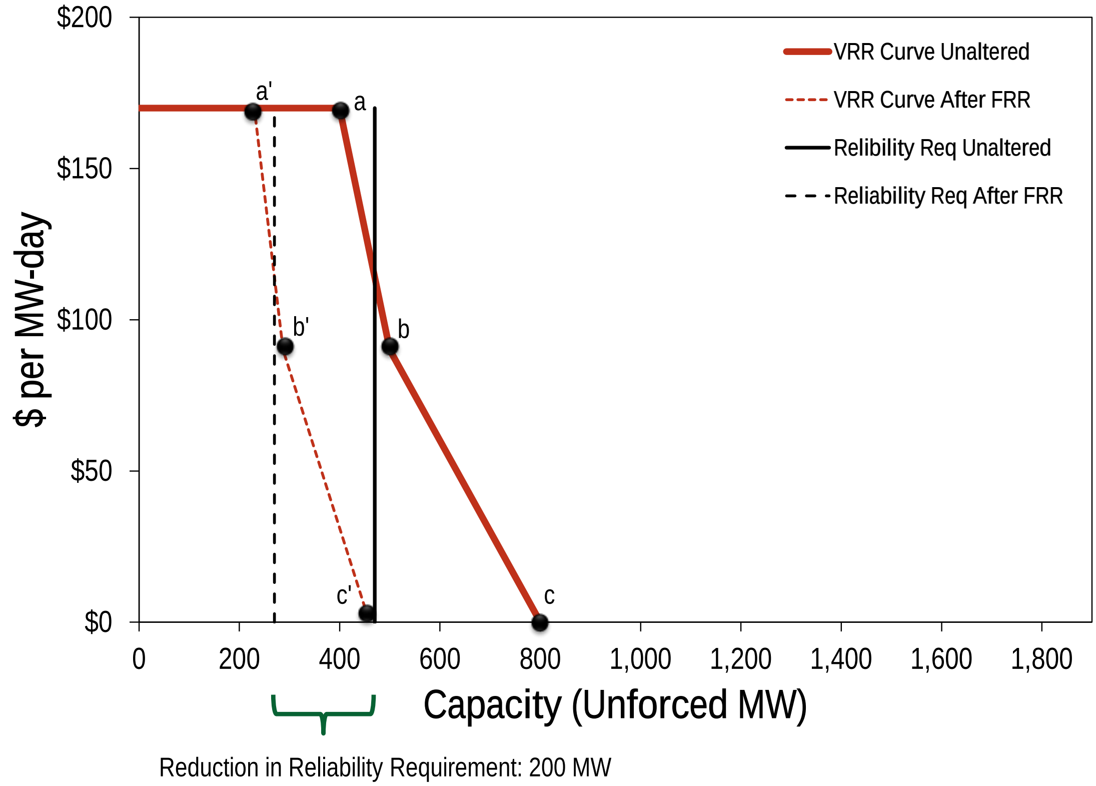

Figure A 6 Clearing of child LDA: Scenario 1

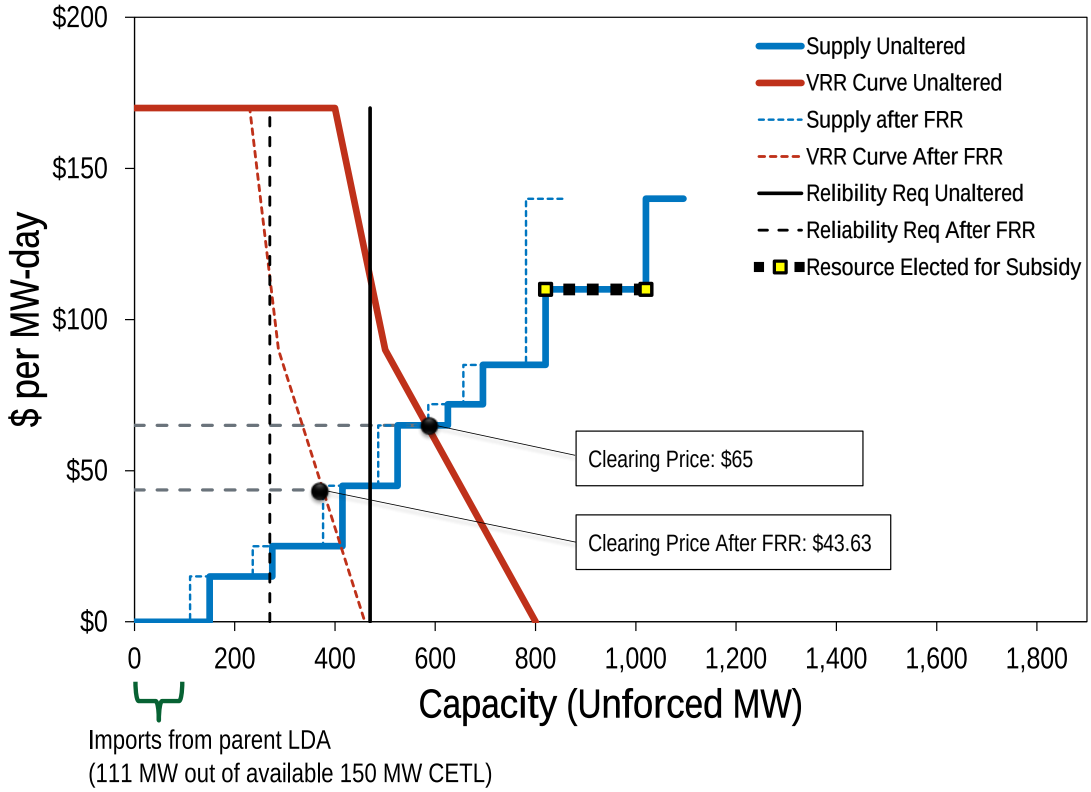

Figure A 7 Clearing of parent LDA: Scenario 1

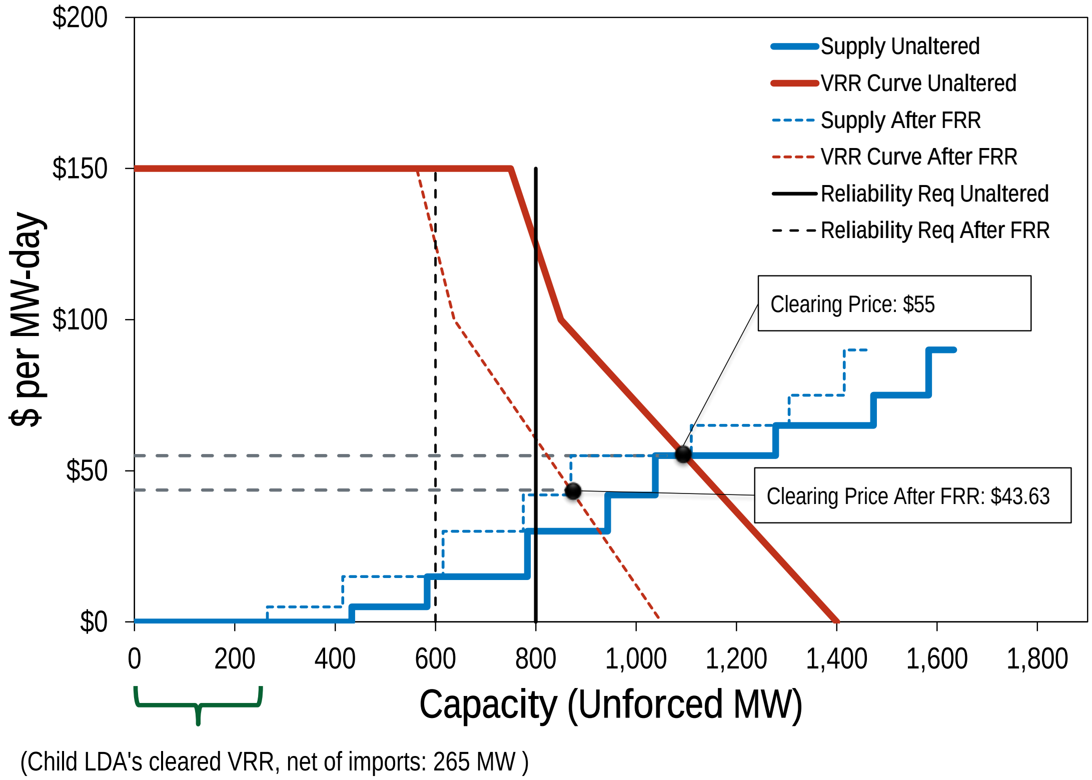

Table A 5 Parameters for VRR curve: Scenario 2

	Child (IRM = 15%, RR = 330 MW UCAP)			Parent (IRM = 15%, RR = 660 MW UCAP)		
	Factors	X (MW UCAP)	Y ($/MW-day)	Factors	X (MW UCAP)	Y ($/MW-day)
a	-17.13%	280.9	170.0	-7.19%	618.8	150.0
b	7.34%	351.1	100.0	7.19%	701.3	100.0
c	80.74%	561.7	0.0	86.25%	1155.0	0.0

Figure A 8 Clearing of child LDA: Scenario 2

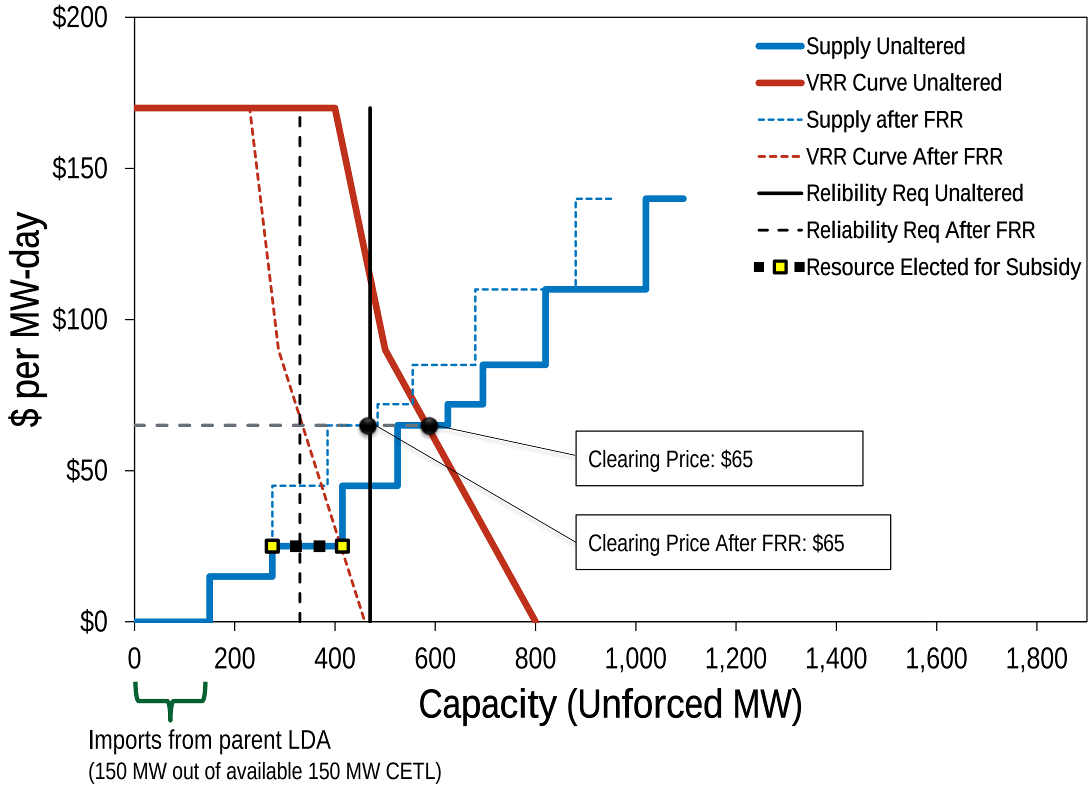

Figure A 9 Clearing of parent LDA: Scenario 2