UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Calpine Corporation, *et al.*	)	Docket Nos. EL16-49-000
	)	
v.	)	
	)	
PJM Interconnection, L.L.C.	)	
	)	
PJM Interconnection, L.L.C.	)	ER18-1314-000
	)	ER18-1314-001
	)	
PJM Interconnection, L.L.C.	)	EL18-178-000 (Consolidated)

INITIAL BRIEF OF NRG POWER MARKETING LLC

Pursuant to the Commission's June 29, 2018 Order requesting briefing in the above referenced dockets (the "Order"),[1] NRG Power Marketing LLC ("NRG") respectfully submits its initial brief, as well as the initial affidavit of Robert Stoddard attached hereto ("Stoddard Affidavit").

I. INTRODUCTION

In the Order, the Commission correctly found that "subsidies allow resources to suppress capacity market clearing prices" to such a degree that the current PJM capacity market is no longer just and reasonable.[2] The Commission found that "[a]n expanded [Minimum Offer Price Rule ("MOPR")], with few or no exceptions, should protect PJM's capacity market from the price suppressive effects of resources receiving out-of-market support by ensuring that such resources are not able to offer below a competitive price."[3] The immediate implementation of a

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[1] *Calpine Corp. v. PJM Interconnection, L.L.C.*, 163 FERC ¶ 61,236 (2018).

[2] Order at P 149.

[3] *Id.* at P 158.

strong MOPR is consistent with the Commission's findings that "we intend to use the MOPR to address the impacts of state policies on the wholesale capacity markets"[4] and its conclusion that "the purpose of basing capacity market constructs on [specified] principles is to produce a level of investor confidence that is sufficient to ensure resource adequacy at just and reasonable rates."[5] It is also consistent with the U.S. Government's recent commitment in its amicus brief to the 7th Circuit that, "[i]f the Illinois program, in fact, impairs the functioning of the wholesale markets subject to FERC jurisdiction" – a question that the Commission has now answered in the affirmative – "the Commission … has the means and the authority to confront those effects."[6]

As the owner of almost 5,000 MW of generation in PJM, many of which will require significant capital expenditures in the next few years, NRG relies on the Commission's commitment to strong capacity market protections to justify its deployment of capital into the PJM footprint. And while a strong MOPR would protect PJM's market from the price suppressive effects of out-of-market subsidies, the Commission's further suggestion concerning a resource-specific Fixed Revenue Requirement Alternative ("FRR-A") threatens to undercut the ability of this market to attract capital.

While the details matter, the FRR-A does not "increase[e] the integrity of the PJM capacity market for competitive resources and load,"[7] as the Commission says it intends, but instead, threatens the workability of the capacity market. Specifically, Mr. Stoddard identifies the following fatal flaws with the FRR-A proposal:

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[4] *ISO New England, Inc.*, 162 FERC ¶ 61,205 at P 22 (2018) ("CASPR Order").

[5] *Id*. at P 21.

[6] Brief for the United States and the Federal Energy Regulatory Commission as Amici Curiae in Support of Defendants-Respondents and Affirmance at 8, *Vill. of Old Mill Creek v. Star*, Nos. 17-2433 and 17-2445 (consolidated) (7th Cir. May 29, 2018).

[7] Order at P 161.

First, removing subsidized generation and load out of the market would appear, as a matter of basic economics, to result in price outcomes that are identical to eliminating the MOPR rule altogether. A world with FRR-A, and a MOPR-in-name-only, would thus result in the same deleterious market ramifications that the Commission already found were not just and reasonable.

Second, the FRR-A proposal would seem to allow state subsidies in one state to significantly affect prices paid by consumers in neighboring states. In some cases, a subsidy program in one state increases costs to consumers in neighboring states. In other cases, a subsidy program in one state suppresses costs in adjoining states. Either way, this type of cross-subsidization appears exactly contrary to the Commission's desire to "confine the cost of a particular state policy decision to consumers within the state that made that policy decision[.]"[8]

Third, the Commission risks interfering with the retail markets established by many of the state legislatures throughout the PJM region. Capacity markets work for retail choice customers because *all* load within a given area pays the same rate for capacity. Allowing certain "carved-out" customers to pay a higher (or lower) capacity rate threatens to disrupt this competitive balance.

Finally, the FRR-A program threatens to create insurmountable affiliate abuse concerns. Many of the largest rent-seeking subsidy-takers are affiliated with Electric Distribution Companies, which effectively act as collection agents for the subsidies demanded by their affiliates. It is inherent in the FRR-A structure that any subsidy arrangement effectively becomes a Commission-jurisdictional payment for capacity service. Such arrangements will have to be evaluated under the just and reasonable standard appropriate for affiliate contracts to

[8] *Id.* at P 162.

prevent over-charging of consumers.

NRG does not fear an "accommodate" approach to capacity markets, if properly constructed.[9] While a "clean" MOPR clearly results in rates within the zone of reasonableness, there are a number of (non-FRR-A) accommodation approaches that could also lead to just and reasonable outcomes. NRG has previously suggested a two-tier accommodative approach in this docket (as well as in other forums[10]) that avoids many of the fatal flaws of the FRR-A approach sketched out in the Order.

Time however, is limited. Crafting an accommodative approach suitable for PJM is going to take many months, if not years and must be carefully considered as any unintended consequences will have long lasting effects. Thus, NRG recommends that whatever the Commission decides on an accommodate approach, it should direct PJM to adopt a clear MOPR prior to the next Base Residual Auction ("BRA"), now scheduled for August 2019. This will ensure that rates in the August 2019 auction are just and reasonable. Longer-term harmonization efforts, however, should be done on a deliberative time frame, with the goal of having the rules completely determined by the 2020 or 2021 BRAs.

II. BACKGROUND

The past several years have seen a proliferation of subsidies across the PJM footprint. For examples, subsidies enacted in Illinois and passed by the New Jersey Legislature are

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[9] *See* Pre-technical Conference Statement of Mr. Peter Fuller and Mr. Abraham Silverman in Docket No. AD17-110-000 framing the "accommodate, adapt, achieve" paradigm of market reforms.

[10] *Id*. *See also* NRG's presentations during the underlying stakeholder process: https://www.pjm.com/-media/committeesgroups/task-forces/ccppstf/20171016/20171016-nrg-two-tier-executive-summary.ashx and https://www.pjm.com/-/media/committees-groups/task-forces/ccppstf/20170717/20170717-nrg-two-tierproposal.ashx.

designed to keep thousands of megawatts of uneconomic generation operating in the PJM market. The uneconomic retention of these generators artificially depresses prices in the PJM energy markets every day, and has, and will continue to, artificially depress prices in PJM's capacity market. Against this backdrop, a coalition of generators filed a complaint at the Commission seeking relief from suppressed capacity market prices in March 2016 in Docket No. EL16-49-000 ("Calpine Complaint").

After two years of Commission and PJM inaction on the Calpine Complaint, during which time the efficacy of the PJM markets suffered, PJM filed two proposals in Docket No. ER18-1314-000, that PJM asserted would protect the market from out-of-market subsidies: the Capacity Repricing Proposal ("PJM Repricing Proposal") and an expanded MOPR proposal ("MOPR-Ex," and together, the "PJM Capacity Proposal"). Both proposals applied to existing and new resources that receive a "material subsidy." The PJM Repricing Proposal utilized a two-stage auction approach to accommodate state actions, while the MOPR-Ex proposal focused on improving the existing MOPR.[11]

In the Order, the Commission found that "it has become necessary to address the price suppressive impact of resources receiving out-of-market support" and "because the current MOPR applies only to new natural gas-fired resources, it fails to mitigate price distortions caused by out-of-market support granted to other types of new entrants or to existing capacity resources of any type."[12] As a result, the Commission found PJM's existing tariff to be unjust and unreasonable.[13] The Commission granted the Calpine Complaint, in part, and *sua sponte* initiated an FPA section 206 proceeding in a new docket – Docket No. EL18-178-000.

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[11] PJM Capacity Proposal at pgs. 51-53.

[12] Order at P 5.

[13] *Id.* at P 6.

A. Commission Order as to PJM's Capacity Filing.

Despite finding that it was necessary for the PJM Tariff to address the price suppressive impact of resources receiving out-of-market support, the Commission rejected both halves of the PJM Capacity Proposal. The Commission rejected the PJM Capacity Repricing Proposal after finding a litany of fatal problems with the proposal:

- It is unjust and unreasonable to separate the determination of price and quantity for the sole purpose of facilitating the market participation of resources that receive out of market subsidies.[14]

- Allowing resources receiving out-of-market subsidies to submit offers into the capacity market as price-takers and acquiring capacity obligations without mitigation, would suppress the capacity market clearing prices, with all other things being equal.[15]

- The two-tier structure of PJM's proposal would result in a final clearing price that would fail to provide accurate price signals for market participants as to new entry pricing or the need for retirements.[16]

- It is unjust and unreasonable, and unduly discriminatory or preferential, for a resource receiving out-of-market subsidies to benefit from its participation in the capacity market, by not competing on a comparable basis with competitive resources.[17]

The Commission also rejected PJM's MOPR-Ex proposal which would have expanded PJM's existing MOPR to new and existing resources that received a Material Subsidy (as defined by PJM), subject to a long host of exemptions. The Commission reasoned that PJM failed to provide a valid reason for the disparity among resources that receive out-of-market support through Renewable Portfolio Standard ("RPS") programs, which would be exempt from the

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[14] *Id.* at P 64.

[15] *Id.* at P 63.

[16] *Id.* at P 65.

[17] *Id.* at P 66.

MOPR-Ex proposal, and other state-sponsored resources, which would be covered by the MOPR rules.[18]

B. The Commission's Suggested Replacement Rate.

In the Order, the Commission established a paper hearing to address the just and reasonable replacement rate for PJM's existing MOPR, including the proposal identified in the Order, as well as other ideas.[19] Under the proposal set forth in the Order, PJM would (i) modify the MOPR to apply to new and existing resources that receive out-of-market payments, regardless of resource type, with few to no exemptions, finding that "[a]n expanded MOPR, with few or no exceptions, should protect PJM's capacity market from the price suppressive effects of resources receiving out-of-market support by ensuring that such resources are not able to offer below a competitive price;"[20] and (ii) brief whether or not to implement a new FRR-A construct that would allow resources that receive out-of-market support to have the option of being removed from the PJM capacity market, along with a commensurate amount of load, for some period of time.[21] The Commission "preliminarily [found] that modifying [these] two aspects of the PJM tariff *may* produce a just and reasonable rate."[22] The Commission acknowledged that the details of the FRR-A would need to be addressed and requested further briefing through paper hearing.[23]

Because of the Commission's concerns about the expanded MOPR resulting in the possibility of some ratepayers being obligated to pay for capacity twice (once through the state

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[18] *Id.* at P 100.

[19] *Id.* at PP 164, 172.

[20] *Id.* at P 158.

[21] *Id.* at PP 167-169.

[22] *Id.* at P 157 (emphasis added).

[23] *Id.* at PP 164, 172.

programs providing out-of-market support and once through the capacity market) the Commission proposed the FRR-A.[24] Under this option, the Commission envisioned that "on a resource-specific basis, resources receiving out-of-market support [could] choose to be removed from the PJM capacity market, along with a commensurate amount of load, for some period of time."[25] Subsidized resources electing the FRR-A option would not participate in the PJM capacity market and would not make or receive payments from the capacity auction. A subsidized resource could forgo the FRR-A option and remain in the capacity auction subject to the expanded MOPR.

III. ARGUMENT

A. Adopting a Strong MOPR Without Exemptions is Necessary to Protect the Market.

1. A MOPR Without Exemptions is the Best Approach to Protect the Market.

A strong MOPR with few to no exemptions is, in and of itself, a viable path forward to a just and reasonable market design and should be implemented immediately. NRG agrees with the Commission's conclusion that "[a]n expanded MOPR, with few or no exemptions, should protect PJM's capacity market from the price suppressive effects of resources receiving out-of-market support by ensuring that such resources are not able to offer below a competitive offer price."[26] Mr. Stoddard concurs with the Commission, concluding that "[a]nything short of such a comprehensive, symmetric rule will undercut PJM's Reliability Pricing Model's ("RPM's") ability to produce competitive prices to support efficient, least-cost resource adequacy for PJM's

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[24] *Id.* at PP 159-160.

[25] *Id.* at P 160.

[26] *Id.* at P 158.

bulk power system."[27]

Under a strong MOPR design, subsidized market participants are required to offer into the market at their true cost. Such a MOPR protects both consumers and investors in existing generation. Consumers are protected against being forced to subsidize sources of capacity that are available from the market at a lower cost and against being forced "to underwrite, through capacity payments, the generation preferences that other regulatory jurisdictions have elected to impose on their own constituents."[28]

Existing generators are protected against the market harm caused by resources receiving subsidies. These non-market offers have dire consequences for the entire market, but take a special toll on existing investors that committed capital into the market with the promise of a just and reasonable market design. As Mr. Stoddard concludes, "[w]ithout an expanded MOPR . . . PJM's capacity prices will likely be pegged below the efficient, competitive level by the action of targeted subsidies by the states, rather than 'the result of competitive market forces.'"[29]

The lack of a strong MOPR is bad not just for capacity suppliers, but also for consumers as well. While the possibility of some ratepayers being obligated to pay for capacity twice is often raised, that stems from conscious decisions made by policy makers on their behalf. If one follows the outcome of such actions to its logical conclusion, those same ratepayers may well be paying again when otherwise economic resources are prematurely pushed out of the market resulting in higher prices or they are forced to shoulder costs associated with out of market retention of resources needed for reliability. As much as the term "jumbo shrimp" is a recognized oxymoron, so too is a "free subsidy."

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[27] Stoddard Affidavit at 15.

[28] Order at P 67.

[29] Stoddard Affidavit at 20 (quoting the Order at P 158).

2. Features of a Strong MOPR

A strong MOPR should include the following features, which are largely consistent with the MOPR PJM put forth during stakeholder meetings:

- MOPR must apply to both new *and* existing resources receiving out-of-market subsidies.
- MOPR must apply to all types of generation.
- MOPR should apply to resources that receive more than 1% of the resource's actual or anticipated total revenues from PJM.
- MOPR must apply to any future discriminatory subsidies imposed at the state or federal level.
- To prevent gaming, rules must be structured so that short-term subsidies, those capable of renewal, or those enacted after the initial BRA, are captured.
- MOPR should extend to all Capacity Resources whether internal or external.

3. The MOPR Should Have No Exemptions.

A strong MOPR should have no exemptions. The Commission expressed concern that PJM did not provide "a valid reason for the disparity" among resources that receive out-of-market support through RPS programs, which would have been exempt from the prior PJM MOPR-Ex Proposal, and other state-sponsored resources, which would have been captured by MOPR-Ex.[30] A MOPR with no exemptions addresses the Commission's concerns by treating all resources comparably. As the Commission reiterated in the Order, "resources receiving out-of-market support are capable of suppressing market prices, regardless of intent."[31]

Any blanket exemptions from MOPR risk exposing captive customers to excessive costs and undermining investment in the market by merchant generators. Economic theory makes

[30] Order at P 100.

[31] *Id.* at P 155.

clear that offering at a resource's cost maximizes a firm's profitability. This is true for all classes of capacity buyers and sellers and it is not clear to us why the Commission would wish to give any license to depart from economically rational behavior.

The one exception to a strong MOPR rule discussed by the Order is whether vertically integrated or public power entities should be covered by the MOPR rules subject to a net short/net long review.[32] The self-supply exemption seeks to accommodate load-serving entities that have traditionally supplied their own capacity without reliance on the wholesale market. Under the proposed exemption, market participants falling within this category can bid below their actual costs so long as their net-short position (how much more they buy from the auction than they sell) or net-long position (how much more they sell into the auction than they buy) is within certain thresholds.

Requiring self-supply entities to offer into the capacity market at their true costs (which, notably, includes their advantaged cost of capital) ensures that only economic generation units are built and that captive ratepayers of self-supply entities are not needlessly overcharged. A blanket exemption from cost-based offers, by contrast, would allow utilities qualifying for the self-supply exemption to commit their captive ratepayers to paying for capacity at a cost in *excess* of what they could buy that same capacity for in the market. These uneconomic ratepayer-backed investments both needlessly increase costs to captive consumers in those service territories and, at the same time, risk replacing merchant generation with subsidized resources bidding below cost.

Further, the exemptions for "self-supply" resources were in effect in PJM from 2013 – 2017 did not work, as NRG highlighted in Docket No. ER18-1314-000. The prior self-supply

[32] *Id.* at P 77.

program never resulted in a single resource being subject to mitigation and clearly resulted in price suppression, which, if allowed to continue unchecked, will drive private capital from the market.

4. The Reasons Offered in the FERC Order for Rejecting a MOPR Only Approach are Not Valid.

The Commission suggested that it added the second element of its proposed mechanism (the FRR-A) after expressing concern over the possibility of some ratepayers being obligated to pay for capacity both through the state subsidy programs and through the capacity market. The Commission itself recognized that while in the past the Commission has found it "acceptable or beneficial to avoid requiring customers to pay twice for capacity as a result of state policy decisions[,]" the "courts have concluded that it need not do so."[33] Specifically, the United States Court of Appeals for the Third Circuit has held that states "are free to make their own decisions regarding how to satisfy their capacity needs, but they 'will appropriately bear the costs of [those] decision[s],' . . . including possibly having to pay twice for capacity."[34] If a state so chooses to subsidize its generation, it is not a double-payment because the state is choosing to have its ratepayers pay for something the state values. It is akin to a choice between a basic healthcare plan and a "Cadillac plan" with richer benefits: it is not a double payment to pay more for a premium plan with additional benefits. Here, the extra costs are being driven by a state's election to pay more to encourage desired outcomes, whether environmental, employment, or any number of goals external to the outcomes of an efficient market.[35] States should not be

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[33] *Id.* at P 69.

[34] *N.J. Bd. Of Pub. Util. v. FERC*, 744 F.3d 74, 97 (3d Cir. 2014) (*citing Conn. Dep't. of Pub. Util. Control v. FERC,* 569 F.3d 477, 481 (D.C. Cir. 2009).

[35] As another analogy, it is well accepted in global economics that an uneven trade deal with a foreign trading partner is ultimately bad for domestic consumers. If a foreign government subsidizes, for example, its steel industry, with the result being that they dump their product in

allowed to externalize the costs of their subsidy decisions onto competitive capacity market participants.

Any concern about ratepayers paying for the attributes a state elects to value should not preclude the Commission from requiring PJM to implement the most economically sound mechanism to prevent the subsidized units from suppressing capacity prices. After all, undermining the efficiency of the PJM market will only result in demanding higher private capital rates of return if the market is structurally unsound, increasing overall consumer costs.

B. The FRR-A Proposal Will Not Work and Would Undermine PJM's Markets.

NRG has grave concerns about the ability of the FRR-A proposal sketched out in the Order to create a workable market structure. While there is certainly a superficial appeal of requiring resources to pick between receiving subsidies or capacity payments, the Order seems to underestimate the fundamental challenges of removing load from the RPM market, while retaining a market that will meet PJM's reliability needs.[36] Indeed, because subsidized resources would continue to suppress capacity market prices, any FRR-A variant seems to invite large buyers to exercise buyer-side market power with the express intent of lowering capacity prices.

As discussed in more detail below, these flaws render any type of FRR-A program almost impossible to implement. And other accommodate approaches would do far less violence to the

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the U.S. market below competitive prices, the negative impact on U.S. companies and consumers is well understood. Yet here, it is not a foreign government that threatens the federally administered competitive markets, but individual states that seek to favor their own local benefits and objectives. In an international market where such uneven trade conditions existed, one would be hard pressed to argue against matching tariffs or other actions to insulate U.S. business from the harmful effects of subsidies.

[36] At a minimum, adopting an FRR-A structure would appear to require re-opening every element of PJM's capacity construct, including the shape of the Variable Resource Requirement, as well as other key parameters that underlie the RPM investment thesis, such as the appropriate cost of capital investors will seek under such a high risk market design.

fundamental RPM paradigm, preserve the benefits of competitive market transparency and could be implemented more expeditiously.

1. The FRR-A Will Suppress Capacity Prices.

As set forth in the Order, the FRR-A option would only be available to resources receiving out-of-market subsidies. By definition, the FRR-A resources are not economic and would not clear the BRA if they bid at their true costs.[37] Mr. Stoddard explains, the FRR-A "contemplates removing a matching quantity of load, and this load would have cleared in the competitive BRA."[38] Removing megawatts of load, and equal amounts of *un*economic capacity, but not removing megawatts of *economic* generation inherently suppresses clearing prices below the just and reasonable level.[39] Mr. Stoddard uses Figure 2 of Exhibit RBS-2 to illustrate the point:[40]

> On a supply stack reflecting true costs, these FRR Alternative resources would be in the high-cost part of the stack that would not have cleared in the BRA. Removing them from the supply stack, therefore, leaves the relevant portion of the supply curve unchanged. But the FRR Alternative *also* contemplates removing a matching quantity of load, and this load would have cleared in the competitive BRA.

After analyzing the impacts of the FRR-A, Mr. Stoddard concludes that "[t]he effect on prices is unambiguous: the FRR Alternative would lower competitive clearing prices."[41] The FRR-A will

[37] Stoddard Affidavit at 39.

[38] *Id.*

[39] *Id.* at 39 and Exhibit RBS-2, Figure 2.

[40] *Id.* at 39.

[41] *Id.* at 39.

undoubtedly lead to lower BRA clearing prices, a lack of investor confidence and "would completely undermine the proper functioning of the MOPR."[42]

Further, the economic distortions created by the FRR-A approach sketched out in the order are highlighted by re-visiting the "Hobbs Model" that was used to develop the original RPM design. The Hobbs Model was designed to lead to an efficient market design under which new generation would be built where and when needed as load increased and units retired.[43] "A critical component of Prof. Hobbs' analysis was that new capacity resources are reliant solely on market revenues and—critically—expect the path of future capacity prices *also* to reflect unsubsidized future entry."[44]

Suppressed prices will not provide accurate entry and exit signals for the market that the Commission has identified as a core principle of capacity markets.[45] As Mr. Stoddard notes "[a] central tenet of capacity markets is that the design must yield prices that support entry of new market-based supply, . . . when and where needed."[46] In an efficient market, new generation would displace retired units and account for load increases, but as illustrated by Mr. Stoddard, if state subsidies that would not otherwise be in the market displace the new supply requirements, than absent an effective MOPR, capacity prices will be suppressed.[47] As Mr. Stoddard recognizes "if investors do not have confidence in the ability of the market to function over time,

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[42] *Id.* at 19.

[43] *Id.* at 22.

[44] *Id.* at 23.

[45] CASPR Order at P 22.

[46] Stoddard Affidavit at 4.

[47] *Id.* at 24.

then private investment is deterred and states will need to provide increasing rounds of subsidies."[48]

2. The FRR-A Would Allow Large Buyers to Freely Exercise Buyer-Side Market Power.

The original intent of the MOPR rules was to deter large net buyers from subsidizing new entry and artificially depressing capacity market prices. A major problem with FRR-A is that it would appear to allow a large buyer (say, a state or municipality) to provide a "material subsidy" to a new gas-fired turbine. By electing to subsidize generation and opting into the FRR-A, the large buyer would decrease capacity prices across all of the buyer's capacity purchases. Nor would limiting FRR-A to only carbon-free generation resources solve the problem, since the same economic principles apply regardless of resource type.

Mr. Stoddard recognizes that, "regardless of the purity of intent of current state programs, the enormous loophole in the MOPR created by the FRR Alternative clearly invites new subsidies in the future whose primary intent is price suppression—exactly what the MOPR was originally intended to foreclose."[49] This all leads to Mr. Stoddard's conclusion that "[s]uch action would directly harm competitive suppliers and, potentially, consumers in neighboring states and, in the long-run, undermine the benefits to all consumers of a sound, stable wholesale market for capacity and energy."[50]

3. The FRR-A Amounts to Having No MOPR at All and is Inconsistent with Prior Commission Precedent.

The *de facto* elimination of the MOPR is difficult – if not impossible – to reconcile with the language in the first portion of the Order, explicitly finding that a market structure that

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[48] *Id.* at 25.

[49] *Id.* at 29.

[50] *Id.*

suppresses prices is not just and reasonable. As Mr. Stoddard concludes, "[a]s proposed, the FRR Alternative functionally destroys MOPR in its entirety" because the "impact on competitive prices is precisely the same impact as if the subsidized unit had been exempted from the MOPR entirely."[51]

In the Order, the Commission found that PJM's existing Tariff was unjust and unreasonable because it established a market structure that suppressed capacity clearing prices. In referring to the existing Tariff, the Commission concluded "[t]hese subsidies allow resources to suppress capacity market clearing prices, rendering the rate unjust and unreasonable."[52] Specifically, the Commission reasoned that the existing Tariff:[53]

> [F]ails 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 concluded that, "the PJM Tariff allows resources receiving out-of-market support to significantly affect capacity prices in a manner that will cause unjust and unreasonable and unduly discriminatory rates in PJM regardless of the intent motivating the support."[54]

The Commission simply cannot ignore that, if implemented as laid out in the Order, the

[51] *Id.* at 20.

[52] Order at P 149.

[53] *Id.* at P 150.

[54] *Id.* P 156.

FRR-A would allow resources with out-of-market subsidies to continue to suppressing capacity market clearing prices and thus, would result in the same price suppression that the Commission found rendered PJM's existing tariff unjust and unreasonable.[55]

Such a holding would also be inconsistent with the findings in other recent Commission Orders in which the Commission found that:[56]

> A capacity market should facilitate robust competition for capacity supply obligations, provide price signals that guide the orderly entry and exit of capacity resources, result in the selection of the least-cost set of resources that possess the attributes sought by the markets, provide price transparency, shift risk as appropriate from customers to private capital, and mitigate market power. Ultimately, the purpose of basing capacity market constructs on these principles is to produce a level of investor confidence that is sufficient to ensure resource adequacy at just and reasonable rates. Where participation of resources receiving out-of-market state revenues undermines those principles, it is our duty under the FPA to take actions necessary to assure just and reasonable rates.

And in July of this year the Commission reaffirmed its "support for market solutions as the most efficient means to provide reliable electric service to . . . consumers at just and reasonable rates."[57] Requiring PJM to adopt an FRR-A that would blatantly suppress capacity prices would be, by the Commission's own recent holdings, unjust and unreasonable.

4. The FRR-A Threatens to Create Zonal and Intra-zonal Winners and Losers.

The Commission concluded that a just and reasonable "capacity construct should help confine the cost of a particular state policy decision to consumers within the state that made that

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[55] *Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co*., 463 U.S. 29, 43 (1983) (An agency must "examine the relevant data and articulate a satisfactory explanation for its action including a 'rational connection between the facts found and the choice made,'" and it is error for an agency to "entirely fail[] to consider an important aspect of the problem") (*quoting Burlington Truck Lines, Inc. v. United States*, 371 U.S. 156, 168 (1962)).

[56] CASPR Order at P 21.

[57] *See ISO New England Inc.*, 164 FERC ¶ 61,003 at P 53 (2018) ("Mystic Waiver Order").

policy decision, whereas the status quo requires consumers in some PJM states to subsidize the policy decisions of other PJM states."[58] Despite the laudable goals expressed in the Order, our analysis suggests that: (i) the FRR-A increases the risk of cross-subsidization by consumers of adjoining states, and (ii) the FRR-A threatens to create winners and losers in retail choice markets.

First, the FRR-A proposal would appear to create cross-subsidization between consumers within the PJM states. As Mr. Stoddard explains, the existence of the FRR-A will undoubtedly impact the clearing prices within PJM zones and will change which zones separate in PJM.[59] For example, the uneconomic retention of a large resource in Zone A may make it more (or less) likely that Zone B binds, which could cause prices to rise significantly for Zone B consumers. There is no way around the fact that the participation of subsidized facilities threatens to radically change prices for neighboring consumers, allowing states to export the costs of their subsidies to other states. An FRR-A scheme does nothing to change this reality of transmission planning. In such cases, unless the Commission directs PJM to use a strong MOPR to set a competitive price, New Jersey's (just to take one example) "hypothetical subsidy [raises] consumer costs in neighboring states…. New Jersey ratepayers are enjoying below-cost capacity from the market, at the expense of consumers in Maryland, Pennsylvania and elsewhere."[60]

Second, how to match load and subsidized generation under the FRR-A proposal in a manner that does not result in intra-zonal cross-subsidization is difficult, if not impossible. Under any type of FRR-A proposal, it is necessary to identify the universe of customers *paying* for the subsidy as well as the universe of customers receiving the *benefits* (i.e., the capacity

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[58] Order at P 162.

[59] Stoddard Affidavit at 58-59.

[60] *Id.* at 59.

credits) associated with the carved-out resource. If the customers paying the subsidies are not the same customers receiving the capacity credit, then there would necessarily be Commission-sanctioned cross-subsidization between otherwise identical retail customers. Those paying for the subsidy would be forced to over-pay, while those receiving the capacity credits would receive a free ride.

FRR-A is particularly troubling in the context of retail choice markets, where state legislators adopted a preference for competition at the retail level. Identifying carved-out load in advance of a three-year forward auction pre-supposes that those customers will be served by the same Load Serving Entity at the time the delivery year arrives.[61] Capacity costs are simply assigned pro-rata based on actual billing determinants established during the delivery year and t The existing retail choice structure thus pre-supposes that capacity is a fungible product that can be assigned to competitive Load Serving Entities on a non-discriminatory basis. But replacing transparent capacity prices with opaque subsidy arrangements threatens this core principle and will almost certainly harm retail competition.

5. Removing an Equal Amount of Load and Generation From the Market is Not Just and Reasonable.

The Commission also requested briefing on the reserve margin that should apply to FRR-A resources. While FRR has its own defined reserve margin slightly in excess of PJM's Installed Reserve Margin between 15% and 16%, the reserve margin for non-FRR regions is calculated by the market in a manner that maximizes consumer reliability, while minimizing total consumer costs (the "Realized Reserve Margin"). As an example, the last BRA committed enough resources to reach a 22% reserve margin.

[61] Indeed, existing FRR regions avoid this problem because there is no choice but to be served by the utility.

While the Realized Reserve Margin may be the "minimum equitable quantity, imposing a somewhat large margin on [carved-out] resources may be warranted."[62] The reserve margin for the FRR-A should be increased to a level higher than the Realized Reserve Margin to account for the fact that the FRR-A load is leaning on the BRA capacity resources for support. This is largely due to the fact that the carved-out load would now rely on a single unit (or small group of units) instead of relying on the entire PJM footprint, to support reliability. It is a truism that reserve margins need to be higher in small balancing authorities, because any given unit may go on a forced outage at any given time. In large balancing authorities, with a broad and diverse mix of assets, it is appropriate to use a smaller reserve margin, reflecting the relative unimportance of any given unit. However, FRR-A load is served by a much smaller suite of assets, which requires a correspondingly higher reserve margin. As Mr. Stoddard recognizes, "a higher reserve margin for FRR Alternative load is appropriate because they are implicitly relying on the whole system, not just their tagged FRR Alternative resources, to provide reliability, and the reliability of those tagged resources is likely to be lower than the aggregate reliability of the system."[63]

To avoid discriminatory treatment, Mr. Stoddard explains that for the FRR-A, PJM should use, at a minimum, the applicable Realized Reserve Margin in determining the amount of load that is matched with to FRR-A capacity.[64] As an example, if the BRA cleared at a 20.5% reserve margin in the same load zone as a 100 MW FRR-A resource, then that 100 MW resource should be matched with 83 MW of load (100/120.5%).[65] With this example Mr. Stoddard

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[62] Stoddard Affidavit at 36.

[63] *Id.* at 36.

[64] *Id.* at 35.

[65] *Id.*

reasons that exempting more load than the 83 MW, has an inequitable result, since the load remaining in the PJM capacity auction would effectively pay for 17 more megawatts than they would have paid for had the FRR-A not been applied.[66] Mr. Stoddard concludes that "[a]n even more extreme disparity arises if the Order's words are taken literally" and the same amount of load and generation are carved out of the auction, the end result would be that "a full 100 MW of load is matched to a 100 MW FRR Alternative Resource, implicitly placing *none* of the cost responsibility for the capacity reserve margin on this load."[67]

6. FRR-A Does Not Contain the Same Market Protections as FRR.

Any resemblance of the FRR-A to PJM's existing FRR program is strictly coincidental. As Mr. Stoddard concludes, "the FRR Alternative diverges from the FRR in several critical respects that would undermine the operation of [a strong] MOPR and, consequently, the RPM."[68] As Mr. Stoddard explains, the FRR was targeted at integrated utilities that had an integrated resource portfolio, comprised principally, of economic generation that was matched to the utility's load obligations.[69] This structure is contrary to that of the FRR-A, which will apply to resources that are, by definition, uneconomic.

While the FRR's "removal of largely economic generation and matched load was expected to have little material impact on market prices," under the FRR-A there will be material impact.[70] Uneconomic generation will be removed from the supply stack (which will not change the market clearing price); however, removing a matched amount of load will shift the

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[66] *Id.*

[67] *Id.*

[68] *Id.* at 8.

[69] *Id.*

[70] *Id.*

demand curve to the left and will lower the capacity price.[71] Thus, the fundamental nature of the FRR (targeting economic generation) as compared to the FRR-A's targeting of uneconomic highlights that the two mechanisms do not share much more than an acronym. Further, the FRR was done at the election of the load serving entity responsible for maintaining capacity sufficient to meet its reliability needs, whereas FRR-A appears to leave the election up to the subsidized resource. In effect, this would give the subsidized resource the capability to "capture" load, whether served by a utility or a competitive retail provider.

Finally, the FRR has included net-short/net-long rules that further inoculated its market impacts. None of these protections are present under the FRR-A. Thus, the Commission cannot rely on its acceptance of FRR as justification for approving FRR-A.

7. An FRR-A Approach Would Deprive Generators of a Reasonable Opportunity to Earn a Reasonable Return of and On Equity.

The Commission must set rates for its regulated entities that are both just (compensatory) and reasonable (fair to the consumer).[72] Investors in the Commission's markets are entitled, as both a statutory and a constitutional matter, to just and reasonable compensation for their power. In a competitive market context, this means that investors must have a reasonable opportunity to

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[71] *Id.*

[72] *See Farmers Union Cent. Exchange, Inc. v. Federal Energy Regulatory Comm.* 734 F.2d 1486, 1502 (D.C. Circuit 1984) stating:

> When the inquiry is on whether the rate is reasonable to a producer, the underlying focus of concern is on the question of whether it is *high* enough to both maintain the producer's credit and attract capital. To do this, it must, *inter alia*, yield to equity owners a return "commensurate with returns on investments in other enterprises having corresponding risks," as well as cover the cost of debt and other expenses. . . . When the inquiry is whether a given rate is just and reasonable to the consumer, the underlying concern is whether it is *low* enough so that exploitation by the [regulated business] is prevented.

recover their fixed costs and a fair rate of return on their investments.[73] Indeed, the Commission has acknowledged that "in a competitive market, [it] is responsible . . . for assuring that [generators are] provided the *opportunity* to recover [their] costs."[74]

While NRG does not believe that the Commission intends to use the FRR-A proposal to undue the enormous benefits of the competitive markets, if it does intend to move towards a "residual" market that is non-compensatory to existing resources, then it must openly acknowledge that it is doing so and address the expectation interests of merchant generators, as well as how it reconciles such a move with its finding in the Mystic Waiver Order supporting competitive markets as the "most efficient means to provide reliable electric service to [ ] consumers at just and reasonable rates."[75]

Titanic shifts in policy require equally significant regulatory proceedings. For example, in the 1980s, FERC restructured the natural-gas industry through a series of orders that began by unbundling pipeline transportation from merchant functions.[76] That order, however, had the effect of "exacerbat[ing]" severe financial stresses on pipelines (which were subject to contractual by take-or-pay clauses that required them to purchase gas from producers at well

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[73] *See* 16 U.S.C. § 824d(a); *FPC v. Hope Nat. Gas Co.*, 320 U.S. 591, 603 (1944); *Bluefield Waterworks & Improvement Co. v. Pub. Serv. Comm'n of W. Va.*, 262 U.S. 679, 692–93 (1923).

[74] *Bridgeport Energy, LLC*, 113 FERC ¶ 61,311 at P 29 (2005); *see also, e.g.*, *Price Formation in Energy and Ancillary Servs. Mkts. Operated by Reg'l Transmission Orgs. & Indep. Sys. Operators*, 153 FERC ¶ 61,221 at P 2 (2015) (the "goals of proper price formation" include "ensur[ing] that all suppliers have an opportunity to recover their costs"); *Midwest Indep. Transmission Sys. Operator, Inc.*, 102 FERC ¶ 61,196 at P 49 (2003) ("[W]e believe that competitive prices over the long run should recover both the fixed and variable costs of efficient generating units[,] and we fear investors may decline to invest in needed generation . . . if they do not see a reasonable expectation of recovering their costs.").

[75] Mystic Waiver Order at P 53.

[76] See *Regulatory of Natural Gas Pipelines After Partial Wellhead Decontrol*, 50 Fed. Reg. 42,408 (1985).

above market prices).[77] Yet FERC decided "to do nothing" about that problem.[78] On appeal, the D.C. Circuit chastised FERC for its "seeming blindness to the possible impact" of its order on pipelines.[79] The court held that FERC's blindness, and "its tendency to elevate into affirmative benefits what are at best palliatives, seem impossible to square with the requirement of reasoned decisionmaking."[80] Although the D.C. Circuit's decision did not direct FERC to adopt a particular remedy, FERC on remand authorized pipelines to recover stranded costs—i.e., costs incurred in connection with bundled sales services that could not be allocated to customers of unbundled services.[81] So long as FERC "adequately balance[s] the interests of investors and ratepayers," the court reasoned, FERC can authorize recovery of all stranded costs.[82]

Similarly, on the electric side, prior to Order 888, utilities had "invested millions of dollars in facilities and purchased power contracts based on an explicit or implicit obligation to serve customers and the expectation that those customers would remain on their systems."[83] Order Nos. 888 and 888-A transformed federal energy policy, rejecting the prior regulatory compact in favor of market-based reforms. That fundamental change left utilities with costs they incurred "not only with regulatory approval, but with the expectation of continuing to serve their

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[77] *Transmission Access Policy Study Grp. v. FERC*, 225 F.3d 667, 683 (D.C. Cir. 2000) ("TAPSG") (per curiam).

[78] *Id.*

[79] *Assoc. Gas Distribs. v. FERC*, 824 F.2d 981, 1025 (D.C. Cir. 1987).

[80] *Id.*

[81] *See United Dist. Cos. v. FERC*, 88 F.3d 1105, 1108 (D.C. Cir. 1996) (per curiam).

[82] *United Dist.*, 88 F.3d at 1108. Ultimately, however, the court remanded the case because FERC had justified cost recovery based on cost-sharing principles but exempted pipelines from shouldering (and thus sharing some of the burden of) stranded costs. *Id.* at 1188-89.

[83] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities*, 62 Fed. Reg. 12,274, 12,276 (Mar. 14, 1997) ("Order No. 888-A").

current customers."[84] Relying on the natural gas precedent discussed above, the Commission read that decision to mean that FERC "cannot change the rules of the game without providing a mechanism for recovery of the costs caused by such regulatory-mandated change."[85] The Commission thus authorized recovery of wholesale costs stranded by the rule it had adopted.[86]

Any move towards replacing RPM with a residual market structure is similar in magnitude to the gas and electric restructurings discussed above. Firms invested in PJM's markets "with the expectation of continuing" to compete to serve the PJM market, pursuant to rules that promote fair competition. Doing otherwise would "change the rules of the game."

Importantly the rules of the existing game include the expectation that those rules will produce price signals to guide investments in new resources.[87] Over the last several decades, firms such as NRG have invested heavily in the PJM market anticipating that the Commission would continue its policy of driving new investment through markets. To the extent the Commission elects to move away from competitive markets and towards a residual market that relies on state subsidies to drive new investment, the Commission must, at a minimum, acknowledge that it is making such a major policy shift and expressly address the expectation interests of investors.

8. Potential for Significant Harm to the Retail Market.

In his dissent to the Commission Order, Commissioner Glick astutely poses the question of whether subsidized resources that opt into the FRR-A could enter into bilateral agreements with load serving entities for the capacity payments they will no longer receive through the PJM

[84] *TAPSG*, 225 F.3d at 683.

[85] Order No. 888-A, 62 Fed. Reg. at 12,373.

[86] *TAPSG*, 225 F.3d at 699. The D.C. Circuit upheld FERC's approach. *TAPSG*, 225 F.3d at 700.

[87] *See New Eng. Power Generators Ass'n, Inc. v. FERC*, 757 F.3d 283, 285 (D.C. Cir. 2014).

capacity market.[88] If the Commission elects to adopt an FRR-A approach, the answer to this question must be "no." Simply replacing capacity revenues, which are competitive and determined transparently, with opaque, non-competitive bilateral contracts leads to a plethora of negative implications, including: lack of transparency, affiliate abuse and negative impacts on retail choice.

a. With Bilateral Contracts, the FRR-A Will Not Create the Transparency Benefits Touted in the Order.

If subsidized entities contract outside the capacity market, the bifurcated structure will create less market transparency and not more. The Commission expected that the "bifurcated approach [would] provide significant benefits through increased transparency for investors, consumers and policy makers."[89] The Commission further stated that, "[t]he bifurcated capacity construct should make more transparent which capacity costs are the result of competition in the capacity market and which capacity costs are being incurred as a result of state policy decisions."[90] However, if subsidized entities can enter into bilateral contracts outside the PJM capacity market, it is less likely that consumers will know the actual cost of capacity.

In the present market, the published PJM capacity clearing price plainly states the cost of capacity for each zone. Carving out certain customers and subjecting them to involuntary bilateral contracts will only cloud the true price customers are paying for capacity. While any capacity revenues (or capacity payments masquerading as subsidy arrangements) would have to be filed with the Commission for approval, consumers would have to dig into the details to understand the basis for their bills. Compounding the problem, "capacity" may be listed as an

[88] *See* Order, Commissioner Glick Dissent, at Section III.B.2.

[89] Order at P 162.

[90] *Id.* at P 162.

average rate across years, combined with the subsidy payments, or in some other fashion that hides the ball. The FRR-A construct would also obscure costs for investors since the auction clearing price would no longer reflect the true cost of all the capacity serving the market.

b. FRR-A Resources Seeking Compensation Through Bilateral Contracts Outside the PJM Capacity Market Could Lead to Significant Affiliate Abuse Issues.

The FRR-A raises serious affiliate abuse concerns where there is the potential for utilities to enter into the bilateral contracts envisioned under the FRR-A with their affiliates, particularly given that some of the largest recipients of the out-of-market subsidies are "unregulated" affiliates of electric distribution companies.

The Commission's regulations prohibit any "wholesale sale of electric energy or capacity between a franchised public utility with captive customers and a market-regulated power sales affiliate without first receiving Commission authorization for the transaction under section 205 of the Federal Power Act."[91] This Commission adopted this prohibition in recognition of the risk of self-dealing and other affiliate abuse that arises when a franchised utility transacts with its affiliates, emphasizing that "it is essential that ratepayers be protected and that transactions be above suspicion in order to ensure that the market is not distorted."[92]

The FRR-A, on its face, enables load serving entities to enter into non-transparent subsidy arrangements, which could be with affiliated entities. Layering on additional bilateral subsidy contracts simply compounds the lack of transparency. As compared to the current RPM structure where the price paid for capacity is transparent as the RPM clearing prices for each zone is made public, under the FRR-A any additional capacity payment could be set by a

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[91] 18 C.F.R. § 35.39(b) (2018).

[92] *Boston Edison Co. Re: Edgar Elec. Energy Co.*, 55 FERC ¶ 61,382 at 62,167 (1991) (footnote omitted). *See also Southern Power Co.*, 153 FERC ¶ 61,068 at P 15 (2015) (same); *Allegheny Energy Supply Co., LLC,* 108 FERC ¶ 61,082 at P 18 (2004) ("*Allegheny*") (same).

negotiated bilateral contract. While bilateral contacts can be an efficient tool in market design, the FRR-A would create new and credible risks of affiliate abuse. The traditional FRR avoids the potential for affiliate abuse because the utility elects to be carved out of the capacity auction along with its generation and load across its entire service territory. The state in which the utility is located has the ability to approve the rate of return and the revenue requirement for that utility and in the event the utility over-collects revenue under the FRR, distribution of that revenue is decided by the state. Whereas, under FRR-A the danger exists that an above market contract would lead directly to the utility's profit without any requirement to return the excess to consumers. The FPA and the Commission's regulations require the Commission to police against such affiliate abuse.

The Commission has granted waivers of this restriction for affiliate transactions involving utilities in much of PJM on the theory that these utilities no longer have captive customers as a result of retail choice.[93] But the Commission has properly rescinded such waivers with respect to utility transactions whose costs are recovered through non-bypassable charges on the grounds that, even if it remains "true that [the utility's] ratepayers will continue to have a statutory right to choose one retail supply over another, . . . [they] are nonetheless captive in that they have no choice as to payment of the non-bypassable generation-related charges" associated with the affiliate transaction.[94] As the Commission explained, "[r]etail choice protects customers from affiliate abuse only to the extent they have a choice to undertake generation costs."[95] As a

[93] *See, e.g.*, *FirstEnergy Solutions Corp.*, 125 FERC ¶ 61,356 at P 13 (2008), *on reh'g*, 128 FERC ¶ 61,119 (2009); *Exelon Generation Co., L.L.C.*, 93 FERC ¶ 61,140 at 61,425 (2000), *on reh'g*, 95 FERC ¶ 61,309 (2001).

[94] *Electric Power Supply Ass'n v. FirstEnergy Solutions Corp.*, 155 FERC ¶ 61,101 at P 55 (2016) ("*EPSA*"). *See also Electric Power Supply Ass'n v. AEP Generation Resources, Inc.*, 155 FERC ¶ 61,102 at P 57 (2016) (same).

[95] *EPSA*, 155 FERC ¶ 61,101 at P 61.

result, such transactions “present the ‘the potential for the inappropriate transfer of benefits from [captive] customers to the shareholders of the franchised public utility’ and, thus, could undermine the goal of the Commission’s affiliate restrictions.”[96]

Given that most subsidy programs involve non-bypassable surcharges, FRR-A enables precisely the inappropriate transfer of benefits from captive customers to shareholders where an affiliated utility is recovering the costs of capacity through a non-bypassable charge. The recovery of capacity costs through non-bypassable charges would present exactly the same affiliate abuse concerns that prompted the Commission to rescind previously granted waivers in past cases. Importantly, PJM’s involvement in the affiliate transaction does not alter the analysis in the slightest, because the Commission’s rules are clear that utilities and their “unregulated” affiliates “are prohibited from using anyone . . . as a conduit to circumvent the affiliate restrictions . . . .”[97]

At a minimum, if the Commission does not create a construct that prevents subsidized resources from entering into separate bilateral contracts for capacity, the Commission should require that any Capacity Market Seller proposing to elect FRR-A treatment for a subsidized resource make a filing under section 205 of the FPA if and to the extent that costs of the capacity costs under the bilateral contracts will be recovered by an affiliated utility through a non-bypassable charge. In any such filing, the Capacity Market Seller would be required to demonstrate that the terms of the affiliate sale satisfy the standards set forth in *Edgar* and *Allegheny*. The purpose of the *Edgar*/*Allegheny* analysis is to “ensure that the buyer has chosen the lowest cost supplier from among the options presented, taking into account both price and

[96] *Id.* at P 55 (quoting *Market-Based Rates for Wholesale Sales of Elec. Energy, Capacity & Ancillary Servs. by Pub. Utils.*, Order No. 697-A, FERC Stats. & Regs. ¶ 31,268 at P 198 (2008)) (alteration in the original; footnote omitted).

[97] 18 C.F.R. § 35.39(g) (2018).

non-price terms . . . ."[98] It is all but inconceivable that the "unregulated" affiliate will ever be the lowest cost supplier in an FRR-A scenario, because it would be irrational for a Capacity Market Seller to elect FRR-A treatment if its costs were below those of the marginal resource in the RPM Auction, to say nothing of actually being the *lowest cost* supplier. As a practical matter, however, the Commission may do better to save itself and all involved the trouble and simply prohibit the use of the FRR-A where capacity costs under the bilateral contracts would be recovered by an affiliated utility through a non-bypassable charge.

c. An FRR-A Approach Could Undercut Retail Choice.

An FRR-A, where subsidized resources have the ability to contract bilaterally for additional capacity payments, would also impede retail choice goals. The Commission Order contemplates that under the FRR-A resources receiving out-of-market support could be removed from the market along with a commensurate amount of load.[99] Such a dynamic could lead to load located in the same zone paying different prices for capacity – not because of competition amongst suppliers, but because of direct action by a state-sponsored entity to subsidize a particular resource. As discussed above, subsidized generation is uneconomic by definition (or else it would not need a subsidy). If the carved-out load is paying the true cost of the generation, that load will be paying higher prices than the surrounding load is paying for PJM RPM capacity. However, there is also a "year 2" problem. If the carved-out load negotiates a fixed payment bilateral contract (or uses a subsidy collected from all customers) in some years, the carved-out load will be paying less than the market price for capacity. In other years it will be paying more for capacity then neighboring load. The ultimate result – one set of customers are paying different capacity prices than another set of customers located in the same zone – interferes with

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[98] *Edgar*, 55 FERC ¶ 61,382 at 62,168.

[99] Order at P 160.

the efficient operation of the competitive market and does not provide a level playing field for all retail providers to compete. Thus, implementation of FRR-A would effectively put the Commission in the unenviable situation of deciding which competing state legislative goals – retail choice or subsidies – are more important.

C. Some Accommodate Mechanisms Could Avoid the Pitfalls of FRR-A.

If the Commission feels the need to supplement a strong MOPR, there are various approaches that the Commission could take to better harmonize its markets with state subsidy programs. NRG has often advocated an accommodate approach to market design.[100] And there are many accommodative programs that would not be as detrimental to the market as an FRR-A approach, including: a two-tier capacity market advocated by NRG at the stakeholder level;[101] a carbon pricing proposal, such as that under consideration in New York; the CASPR proposal in New England; or, potentially, the Resource Carve Out Proposal, or "ReCO", set forth by PJM during the stakeholder process, which included a price redetermination aspect and the payment of lost opportunity costs to existing generators being pushed from the market by the subsidized resources.

What is clear, however, is that the Commission must act to address the harms it identified in the Order immediately. The best way to fulfill its statutory obligation is for the Commission to require PJM to adopt a clean MOPR with no exemptions while it further evaluates an accommodate approach, with the goal of having such an approach implemented for the 2020 or

[100] *See PJM Interconnection, L.L.C.,* "Protest of the NRG Companies" Docket No. ER18-1314 at 3, 25-27 (filed May 7, 2018). ("Philosophically, NRG agrees with PJM that either an "accommodate" approach or a "MOPR" approach could result in just and reasonable rates. However, both PJM Proposals miss the mark.").
[101] *See supra* n. 10.

2021 BRAs.

1. Any Accommodate Approach Should Not Harm Existing Market Participants.

The key to any just and reasonable accommodate proposal is whether the proposal provides merchant resources (i.e., those relying on the market for their economic viability) access to capacity revenues that are not suppressed by state actions (the "price" element) and award merchant resources the same quantity of capacity supply obligations (the "quantity" element) as would exist in an unsubsidized market.

a. Capacity Prices for Merchant Resources Must Reflect the Costs of the Marginal Merchant Resource.

Any successful accommodate approach must provide merchant resources access to a source of capacity revenues that are not suppressed by state policy goals. Because the subsidized resources are receiving their capital cost recovery from outside the market, it is appropriate to pay them less in the capacity market (or, to eliminate any payment, as contemplated under the FRR-A). But unless the market holds forth the prospect that merchant resources can compete to earn an appropriate return of and on equity, the capacity market will fail to attract the capital necessary to meet RPM's reliability goals.

Under the ReCO approach that PJM set forth in the stakeholder process, eligible subsidized resources may elect to "opt out" of having to compete in RPM to earn a capacity supply obligation. Instead, these opt-out resources are simply awarded a capacity obligation – regardless of how expensive they may be – but in exchange agree to forgo any capacity market revenues. As an integral step to the process, PJM must then re-determine the capacity price applicable to merchant units based on a supply stack that removes subsidy-takers ("Price Redetermination"). As Mr. Stoddard notes, "[w]hile clearing prices would still vary as supply and demand conditions shifted, they would be insulted from the regulatory risk created by state auction."[102]

Price Redetermination, however implemented, does not run afoul of the Commission's reasons for rejecting the PJM capacity repricing proposal set forth in the Order. In the Order, the Commission's found it was "unjust and unreasonable to separate the determination of price and quantity for the sole purpose of facilitating the market participation of resources that receive out-of-market support."[103] The Commission expressed concern about the separation of price and quantity based on a belief that it would artificially inflate the capacity market clearing price to compensate for the participation of subsidized resources, and would not accurately send correct price signals to the market with respect to entry and exit.[104] However, the Commission expressly confined this finding to the prior PJM Capacity Repricing proposal, "as submitted, as a stand-alone solution to address the impact of resources receiving out-of-market support in PJM's capacity market."[105]

Several of the Commission's additional concerns about PJM's prior repricing proposal would not apply to a revised repricing proposal that pays merchant resources the unsubsidized price, but pays subsidy-takers less (or zero). For example, the Commission was concerned that it was improper for "a resource receiving out-of-market payments to benefit from its participation in the PJM capacity market, by not competing on a comparable basis with competitive resources."[106] Eliminating payments to subsidized resources opting out of receiving capacity

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[102] Stoddard Affidavit at 56.

[103] Order at P 64.

[104] *Id.* at PP 64-65.

[105] *Id.* at P 65.

[106] *Id.* at P 66.

payments resolves this concern. Further, a revised repricing proposal may not increase prices for load under certain design parameters. This result is consistent with the Commission's observation that load "should not be required to underwrite, through capacity payments, the generation preferences that other regulatory jurisdictions have elected to impose on their own constituents."[107] As Mr. Stoddard concludes, a repricing "approach ensures that the quantity and price from a fully competitive outcome are preserved, while allowing all state-sponsored and other subsidized resources to participate as capacity resources."[108]

b. Quantities of Capacity Supply Awards Must Allow "In-Between" Units to Clear or Must Compensate Displaced Units.

For the capacity market to work, investors must have confidence that they can compete to serve the entirety of the PJM load or receive appropriate compensation if they are forced out of the market because an opt-out resource took their "spot." Under any accommodate approach, if otherwise economic merchant units are pushed out of the market to allow for the subsidized units (known as "in-between" units), the in-between units must be compensated to address the reliance interest of generators on "the expectation of continuing to serve their current customers."[109]

The Commission does not need to develop a solution to this issue out of whole cloth. The problem of how to appropriately treat in-between units has been amply briefed in prior proposals to the Commission, including the "megawatt pro-rationing" proposal advanced by NRG in connection with its two-tier capacity market program.[110] Under megawatt pro-rationing, the in-between units are assigned a capacity supply obligation with all the rights and obligations associated with clearing the auction. The extra costs associated with paying these units are

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[107] *Id.* at P 67.

[108] Stoddard Affidavit at 52.

[109] *TAPSG*, 225 F.3d at 683.

[110] *See supra* n. 10.

collected pro-rata from all cleared resources by reducing each unit's award by a small percentage. In the context of carving the subsidized units out of the market like under an FRR-A framework, it may be sensible to assign the cost of compensating the in-between units to the subsidized opt-out units, since they are the ones causing these additional costs to be incurred.

c. Aspects of the ReCO Proposal Appear Workable FRR-A Accommodations.

The ReCO, as described by PJM in the stakeholder process, implements the FRR-A approach sketched out in the Commission's Order in ways that appear to better promote market efficiency while accommodating state policy goals.

First, one of the most problematic elements of the FRR-A proposal is that proper implementation of any proposal carving load and generation out of the market would require dynamic adjustments to the PJM demand curve (known as the "Variable Resource Requirement" curve) based on how much load sought to exit the market in any given year. To avoid this potentially insurmountable implementation issue, the ReCO proposal leaves subsidized resources and the matched load in the BRA.[111] It also ensures that Local Delivery Areas continue to bind (or not bind) on an appropriate basis, thus ensuring reliability.

Second, the carved out subsidized resources receive a capacity obligation and are subject to the corresponding capacity requirements associated with PJM's landmark Capacity Performance rules, including performance penalties and bonuses, but do not receive capacity payments through the auction. As Mr. Stoddard concludes, "[t]his approach is superior to withdrawing these resources from the capacity construct entirely because it provides the same financial incentives to carve-out resources and competitive resources to offer high-quality resources to the market and to maintain and operate them so as best to support system reliability

[111] Stoddard Affidavit at 47.

needs."[112]

Third, PJM requires that the ReCO, once elected, must last for an appropriate period of time to prevent the subsidized resource from "toggling" between the "higher of" the market price or the subsidy. An appropriate stay-out period "properly limits the ability of a resource to earn the higher of cost or market"[113] and toggle between the two, further harming the capacity market.

Fourth, PJM has recognized the potential for affiliate abuse and the need for the Commission and PJM to develop a mechanism for filing any rates for capacity service at the Commission.[114] As discussed in Section III.B.8.b above, NRG strongly agrees that resources carved out of the capacity auction should, at a minimum, be required to make a filing under section 205 of the FPA if and to the extent that the facility's costs are being recovered by an affiliated utility through a non-bypassable charge. The Commission has an obligation under the FPA to protect consumers from affiliate abuse and requiring PJM to establish any sort of carve out construct. Allowing generators and affiliated utilities to file such costs under their existing market-based rate authority, would not provide the Commission with sufficient ability to review and approve the rates of the agreements.

IV. RESPONSES TO COMMISSION QUESTIONS POSED IN THE ORDER

165. The appropriate scope of out-of-market support to be mitigated by the expanded MOPR, thereby rendering a resource eligible for the new resource-specific FRR Alternative. Also, for units that choose the resource-specific FRR Alternative and need to cover their Avoidable Cost Rate outside of the capacity market, how should the Tariff address that need both procedurally and substantively?

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[112] *Id.* at 43.

[113] *Id.* at P 44.

[114] https://www.pjm.com/-/media/committees-groups/committees/mrc/20180815-special/20180815-item-02-current-approach-to-ferc-order-on-capacity-markets.ashx

Response:

The expanded MOPR should broadly capture material out-of-market actions. NRG has generally supported PJM's definition of "Actionable Subsidy" defined in their April 9, 2018 filing with the exception that there should be no minimum megawatt threshold. As noted throughout this pleading, NRG disagrees with the Commission's FRR-A, but in the event the Commission adopted such an inappropriate design, it is not the Commission's role to ensure units receiving subsidies further recover their Avoidable Cost Rate. As discussed in Section III.B.8.b above, the FRR-A raises serious affiliate abuse concerns where there is the potential for utilities to enter into the bilateral contracts envisioned under the FRR-A with their affiliates, and consistent with its obligations under the FPA, the Commission should require that any Capacity Market Seller proposing to elect FRR-A treatment for a subsidized resource make a filing under section 205 of the FPA if and to the extent that costs of the capacity costs under the bilateral contracts will be recovered by an affiliated utility through a non-bypassable charge.

166. How to identify the load that will be removed from the PJM capacity market auction in connection with resource owners choosing the resource-specific FRR Alternative. This is an important issue because the load associated with each such resource will not have an obligation to purchase capacity from the auction. In addition, we request comments on whether part of a resource should be eligible for the new resource-specific FRR Alternative, as well as how to address resources with split ownership.

Response:

As discussed herein, it is inappropriate to remove load from the PJM capacity market auction beyond the exception currently existing FRR rules. As Stoddard notes: [115]

> FRR was a workable bolt-on to the RPM design, removing both the load and resources of an entire control area, because the intended users were integrated utilities that brought a balanced portfolio, composed principally of economic generation constructed to meet the utility's load obligations. Thus, removing

[115] Stoddard Affidavit at 8.

> both the load and the generation of FRR Entities was expected to have little material impact on market prices; this inoculation of the markets was further reinforced by the net-short/net-long rules applied to FRR Entities.

Removing specific resources as the Commission contemplates in the FRR-A will lead to uneconomic outcomes incompatible with the Commission's stated preferences for competitive market outcomes. As Stoddard further notes:[116]

> [FRR-A] resources are, by definition, not economic, so removing them from the supply stack does not change which resources should clear the RPM. But removing a matched amount of load lowers the capacity clearing price. Moreover, there are serious competition issues raised by the potential mismatch between which load is credited with the FRR Alternative capacity and which load pays the underlying subsidy.

The underlying concern here is that the load assigned the FRR-A megawatts is likely an individual unit or two, putting reliability risk in the hands of a single (or few) units instead of the system-wide redundancy the market relies on in general. If the Commission insists on adopting an FRR-A approach, as discussed in Section III.B.5, the Commission should require PJM to appropriately gross-up the load removed from the auction to account for a reserve margin appropriate for a single-unit balancing authority and to ensure that the removed generation remains subject to Capacity Performance rules.

167. As discussed above, the proposed replacement rate would expand the MOPR to new and existing resources receiving out-of-market support with few to no exemptions. We request comment on the types of MOPR exemptions that should be included. For example, should an exemption be included for self-supplied resources used to meet loads of public power entities? Alternatively, should those resources have the option to use the resource-specific FRR Alternative? What, if any, exceptions should be added to the MOPR for existing resources in the capacity auction?

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[116] *Id.*

Response:

NRG strongly agrees with the Commission's underlying premise that for those resources which meet the threshold for actionable subsidies, few to no exemptions should be allowed from the application of MOPR. No resources should be categorically exempted from the MOPR, including self-supply resources. See NRG's comments above in Section III.A.3. As Mr. Stoddard concludes, no self-supply exemption is necessary:[117]

> The intent of the Self-Supply carve-out was to allow these utilities to continue using 'long-standing business models,' including owning a supply portfolio balanced with the utility's load. Under this new package of changes, however, Self-Supply entities can offer its existing and planned resources using the RCP, thus ensuring that they receive a Capacity Obligation for those resources and neither paying nor receiving capacity charges for the associated MWs.

168. Another issue is the length of time resources receiving out-of-market support who chose the resource-specific FRR Alternative must remain outside of the PJM capacity market auction and the mechanism by which such resources can return to the auction. One possibility is that a resource choosing the resource-specific FRR Alternative would be required to continue as an FRR resource for the duration of its out-of-market support. However, there may be factors favoring a longer period, or perhaps a fixed period of time such as five years.

Response:

While NRG does not support the FRR-A as contemplated by the Commission, whatever mitigation and accommodation methodology the Commission determines is just and reasonable must apply for at least the term of the subsidy itself, plus a period of years. Otherwise, the subsidized resource will take the subsidy when market prices are low, but then forgo the subsidy when market prices are high, effectively toggling between the higher of market prices or the subsidy. Once a resource elects to leave the market, it should not be allowed back. As Stoddard

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[117] *Id.* at 15.

notes, this approach "properly limits the ability of a resource to earn the higher of cost or market."[118]

169. Additionally, we request comment on how the resource-specific FRR Alternative would accommodate required reserves for the load pulled from the PJM capacity market, as well as whether any changes to the demand curve would be necessary to accommodate the resource-specific FRR Alternative. We also seek comment on the best approach to ensure locational resource adequacy needs are met after removing load and resources from the capacity market under the FRR Alternative. Finally, we seek comment on whether the existing Capacity Performance construct for FRR resources can be applied to a resource-specific FRR Alternative.

Response:

As Mr. Stoddard discusses, removing load and generation from the RPM fundamentally disrupts the existing demand curve structure utilized by PJM, at both the RTO level, as well as in specific LDAs. Not only do the existing demand curves no longer work, but the fundamental analysis of Professor Hobbs, related to investment decisions and necessary rates of return, would be fundamentally disrupted by shifting generation and load out of the competitive market.

Further, Mr. Stoddard notes the fundamental differences between the existing FRR and the proposed FRR-A. For the reasons discussed in Section III.B.6 above, the rules applicable to FRR make a poor analogy to the FRR-A. Regardless of the method by which the market addresses subsidized units, such resource should be subject to the same Capacity Performance standards and restrictions associated with typical FRR resources.

170. The Commission recognizes that, as with any market design, there is some degree of uncertainty concerning how this new bifurcated capacity construct will function in practice, and how the departure of state-subsidized resources might impact capacity market prices. If there are scenarios in which the FRR Alternative could affect the competitiveness of the capacity market clearing prices, parties should explain those scenarios in the paper hearing. In addition, we note that other significant changes to PJM's capacity market have employed mechanisms to transition to the new construct. We seek comment on whether any such mechanisms or other accommodations would be necessary here to facilitate the transition to this new capacity construct.

[118] *Id.* at 44.

Response:

It is undeniable that the FRR-A described by the Commission will impact capacity market prices in negative ways. See Section III.B above. As Stoddard makes clear:[119]

> The FRR Alternative is explicitly intended for resources that are not economic. On a supply stack reflecting true costs, these FRR Alternative resources would be in the high-cost part of the stack that would not have cleared in the BRA. Removing them from the supply stack, therefore, leaves the relevant portion of the supply curve unchanged. But the FRR Alternative also contemplates removing a matching quantity of load, and this load would have cleared in the competitive BRA. The effect on prices is unambiguous: the FRR Alternative would lower competitive clearing prices.

If the Commission intends to adopt the FRR-A, which NRG strongly urges FERC not to do, a better path forward would be to implement the MOPR rules as an interim solution for the 2019 BRA and then, due to the complexity of an FRR-A and accommodate approaches (as further described in Sections III.B and III.C above), provide time for PJM to further develop such an approach.

171. Finally, some intervenors raise the question of whether federal sources of out-of-market support should be addressed by Commission action, and others question how major capacity market reforms will interact with PJM's ongoing fuel security initiative. Parties should also consider these questions in their comments, as well as whether to incorporate the administratively determined minimum offer prices from PJM's MOPREx proposal or to establish different minimum offer prices.

Response:

A strong MOPR should capture Actionable Subsidies regardless of their source, be it initiated by states or the Federal Government. With respect to the ongoing fuel security initiative, it is premature to determine precisely how any such efforts will interact with PJM's capacity market. If one presumes that some form of fuel secure requirements exist in the future, then the net

[119] *Id.* at 39.

revenue stream from such requirement would be reflected in the net revenues of applicable resources. Finally, PJM should utilize minimum offer prices consistent with the resource class as previously articulated by PJM to ensure reasonable offers are made by units subject to the Actionable Subsidy and application of MOPR.

V. CONCLUSION

NRG respectfully requests that the Commission require PJM to implement a MOPR with no exemptions in time for the 2019 BRA. This is only interim solution that will stop the hemorrhaging of the wholesale market in a meaningful way while the Commission continues to discuss various accommodate approaches.

October 2, 2018

Respectfully submitted,

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Certificate Of Service

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

Dated at Princeton, New Jersey this 2nd day of October, 2018.

/s/ *Maria DeLuca*

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Calpine Corporation, *et al.* v. PJM Interconnection, L.L.C.	Docket Nos. EL16-49-000
PJM Interconnection, L.L.C.	ER18-1314-000 ER18-1314-001
PJM Interconnection, L.L.C.	EL18-178-000 (Consolidated)

AFFIDAVIT OF ROBERT B. STODDARD
ON BEHALF OF NRG POWER MARKETING LLC

I, Robert B. Stoddard, being duly sworn, depose and say:

I. Qualifications

1. My name is Robert B. Stoddard. I am an economist and principal of Power Market Economics LLC at 28 Monument Square, Portland, Maine 04101. I am also the president and chief executive of GWave LLC, an ocean wave energy technology firm. As CEO of GWave, I provide executive leadership for a technology startup developing a new generation of ocean wave energy converters. Prior to joining GWave, I led the energy practice at Charles River Associates, a global consultancy, where I remain a senior consultant. My consulting work focuses on electricity industry restructuring, capital investment in power markets, and providing both strategic analyses and testimony for utilities, generation owners, and governments regarding the practical implications of market design. I have frequently testified to the Federal Energy Regulatory Commission ("the Commission") as well as to state utility commissions and legislatures on competitive market design, rates, and market power issues, particularly in the regions managed by the northeastern Regional Transmission Organizations. Related to this docket, I was closely involved in the original proceedings to implement the Reliability Pricing Model ("RPM") in PJM and helped to fashion the original Minimum Offer Price Rule ("MOPR"), and I have submitted affidavits on behalf of the NRG Companies in

subsequent proceedings to refashion the MOPR.[1] I have also been active in the parallel New England Power Pool ("NEPOOL") Integrating Markets and Public Policy ("IMAPP") discussions, which led to ISO New England's filing of the Competitive Auctions with Sponsored Policy Resources ("CASPR") rules, recently approved by the Commission.[2] I was an invited speaker at the Commission's technical conference on this topic last year.[3] I hold degrees in economics from Amherst College and Yale University. My complete *curriculum vita* is attached as Exhibit RBS-1.

II. Purpose and Background

2. I have been asked by NRG Power Marketing LLC ("NRG") to review and respond to the Commission's recent Order in this docket and PJM's proposed market rule changes, as they have been discussed with stakeholders. Broadly speaking, the Order contemplates two major revisions to PJM's RPM design. First, the MOPR should be strengthened and expanded to include all capacity supply resources that receive a Material Subsidy and, consequently, offer into the RPM at prices that do not reflect their true costs. Second, the Order sketches a Fixed Resources Requirement Alternative ("FRR Alternative") whereby subsidized supply resources ("FRR Alternative Resources") and an equal amount of load can be matched and removed from the market, bifurcating the market for subsidized and market-based resources.

3. The issue of whether and how subsidized resources should participate in capacity constructs is the core issue in this docket and related cases in New England and California.[4] Allowing subsidies to suppress wholesale capacity prices systematically causes serious economic distortions, including allowing states to exercise buyer-side market power through price suppression, to recover part of their subsidy costs from consumers in other states and from competitive suppliers, and masking the true cost of those subsidies to consumers. While some argue that simply excluding subsidized resources result in substantial over-procurement, resulting in excessive investment and higher societal and consumer costs, allowing subsidies to distort wholesale prices provides a distorted incentive for states to foster such inefficient investment. As demonstrated by the extensive work by PJM and stakeholders on these issues, striking a

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[1] *PJM Interconnection, LLC*, Docket No. ER13-535.

[2] *ISO New England, Inc.*, 162 FERC ¶ 61,2015 (2018) *("CASPR Order").*

[3] State Policies and Wholesale Markets Operated by ISO New England Inc., New York Indep. Sys. Operator, Inc. and PJM Interconnection, LLC, Docket No. AD17-11-000.

[4] *See ISO New England, Inc.*, 162 FERC ¶ 61,2015 (2018) ("CASPR Order); *CXA La Paloma, LLC v. California Indep. Sys. Operator Corp.*, Docket No. EL18-777-000.

balance between maintaining competitive markets and accommodating state subsidies is not an easy task.

4. The first priority in this docket must be the preservation of the proper functioning of the RPM. A central tenet of capacity markets is that the design must yield prices that support entry of new market-based supply, re-investment in existing resources, and efficient exit of uneconomic resources, when and where needed. To achieve these goals it is not enough that prices are high in one year when new entry is required, but rather the path of prices over the years should average at the net cost of new entry, as the market cycles through periods of scarcity and surplus. The Commission has recognized this necessity many times, first with the establishment of the sloped Variable Resource Requirement ("VRR") demand curves in PJM and most recently with the acceptance of similarly sloped capacity demand curves in ISO New England.

5. Sloped demand curves are necessary but not sufficient for RPM to yield appropriate long-term capacity prices without excessive volatility and cost. It is also necessary that supply offers reflect the underlying costs of capacity, and that offers not meeting this criterion be mitigated. PJM's RPM includes rules to mitigate offers that are either above *or* below their true costs and threaten to disrupt formation of efficient, cost-based prices. The MOPR discussed in the Order contemplates a substantial expansion of the application of the rule that protects the market from below-cost offers. This expansion is entirely justified and, indeed, necessary to protect the sound operation of the RPM. When the MOPR was first proposed as part of the original settlement agreement, it was controversial and, consequently, parties agreed to a narrowly constructed rule that dealt with the most pressing issue at the time: the subsidies being considered by several states to developers of gas-fired generation. The discussion in these states was clear: the principal benefit of the state-sponsored resources was the suppression of wholesale prices for energy and capacity. The MOPR was designed to eliminate the potential for capacity price suppression and thus eliminate the incentive to build new resources unless and until market prices supported competitive entry. Since then, the scope and scale of state-sponsored resources has changed and expanded, and the intent is more complex. It remains essential, however, that PJM's market design not provide price-suppression incentives for state support of capacity resources, regardless of vintage or technology. The MOPR design contemplated in the order (which I refer to as the "Extended MOPR") could be appropriately constructed to protect the integrity of the wholesale capacity market.

6. Other than approving an Extended MOPR, the Commission need take no additional action in this docket.

   - Nothing in the RPM as amended with an Extended MOPR prevents states from undertaking whatever action they choose with respect to building or subsidizing generation, although it clearly affects the cost to states of such action.

   - The Extended MOPR will ensure that prices are in the zone of reasonableness, reflect true societal costs of maintaining resource adequacy, and yield prices that are not unduly discriminatory.

   The Order and PJM's filing contemplate, however, further market changes for achieving the competing goals of market integrity and state accommodation. Although I think that no accommodation is necessary, any accommodation must ensure that RPM will continue to provide a viable path of prices to support the region's long-term capacity needs.

7. The Commission's suggested approach, the FRR Alternative, fails any rational test of viability. The FRR Alternative allows state subsidies to cause unfettered distortions of federal capacity markets, ultimately gutting the ability of the markets to function properly. It would effectively remove the MOPR by allowing any resource that would be affected by the MOPR to opt out and rely on subsidies (and, possibly, bilateral contracts). Moreover, there are serious competition issues raised by the potential mismatch between which load is credited with the FRR Alternative capacity and which load pays the underlying subsidy. Consequently, I believe that, if the Commission chooses to provide a path for accommodating state-subsidized resources, the FRR Alternative approach sketched in the Order is not a just and reasonable market design.

8. Some suggest that the FRR Alternative echoes the design of the Fixed Resource Requirement ("FRR") that was crafted during the original RPM settlement process. However, the FRR Alternative diverges from the FRR in several critical respects that would undermine the operation of the Extended MOPR and, consequently, the RPM. FRR was a workable bolt-on to the RPM design. Because the intended users were primarily integrated utilities that brought a resource portfolio, composed principally of economic generation that was balanced to meet the utility's load obligations. Thus, FRR's removal of largely economic generation and matched load was expected to have little material impact on market prices. This inoculation of the markets was further reinforced by the net-short/net-long rules applied to FRR Entities. But when this same concept is applied to individual supply resources, as proposed in the FRR Alternative, the result is

very different. These resources are, by definition, *not* economic, so removing them from the supply stack does not change which *resources* should clear the RPM—a resource mix that does not include the FRR Alternative units. Thus the relevant portion of the MOPR-mitigated capacity supply curve is unchanged: the mitigated offer prices of FRR Alternative resources are *higher* than the expected clearing price, *i.e.* located to the right of the (mitigated) market equilibrium, so removing them from the supply stack has no impact on the market clearing. See Figure 1 of Exhibit RBS-2. But removing a matched amount of load shifts the demand curve leftward and lowers the capacity clearing price.[5] See Figure 2 of Exhibit RBS-2.

9. Unfortunately, PJM's core proposal fails to make these necessary changes. The Resource Carve Out ("ReCO") introduced by PJM differs from the FRR Alternative in some important ways but shares the same fatal flaw as the FRR Alternative: allowing state subsidies to cause unfettered distortions of federal capacity markets, ultimately gutting the ability of the markets to function properly. PJM proposes supplemental design features that would redetermine the Resource Clearing Price and pay resources squeezed out of the BRA their Lost Opportunity Cost. As I discuss in Section VI below, these supplemental features are one way of removing some of the distortion caused by ReCO.

10. I conclude this affidavit with a discussion two approaches for applying a resource carve-out, akin to the FRR Alternative to accommodate state policy decisions while protecting the integrity of PJM's wholesale markets. The first is a modest change to the quantity pro-rationing approach I discussed in the docket leading up to the Commission's Order instituting this docket. The second is the capacity pricing approach presented by PJM in its final stakeholder meeting as an additional part of its filing. PJM's new approach supplements the ReCO with a redetermination of Resource Clearing Prices based solely on competitive or cost-based offers, thereby ensuring that the prices paid to market-based resources remain at competitive levels, and providing a Lost Opportunity Cost payment to competitive resources that were crowded out by subsidized resources. This extension represents a significant evolution from the repricing design PJM proposed in its earlier filing.[6] It does not risk over-procuring resources, nor does it distort incentives for suppliers to offer at competitive prices. It fully credits load for those resources it designates as self-supply while ensuring that market prices reflect the true marginal costs of ensuring resource adequacy. Although there are important implementation

[5] In these charts I assume that the amount of load matched to each FRR Alternative resource is determined by the capacity reserve margin as cleared in the BRA.

[6] *See PJM Interconnection, L.L.C.*, 163 FERC ¶ 61,236 (2018) ("Order").

details to an overall package that could reasonably accommodate subsidized resources (namely, ReCO plus a capacity price redetermination plus lost opportunity cost features) that I cannot address prior to reviewing PJM's filing in this docket, this structure or the quantity pro-rationing approach—taken as a whole and including the Extended MOPR—would support the effective bifurcation of the market without impairing the ability of the competitive side of the market from attracting and retaining efficient levels of capacity.

III. MOPR IS A CORE ELEMENT OF THE RPM MARKET DESIGN AND SHOULD BE APPLIED WITHOUT EXEMPTIONS

11. A robust MOPR is an essential part of the RPM market design to ensure that wholesale capacity prices are competitive and efficient. Just as market operators and market monitors review offers to ensure that prices are not raised by supply offers that *overstate* the true costs of a capacity resource, the MOPR enables the market operator and market monitor to perform the symmetric function of preventing supply offers that *understate* their true costs from unduly influencing market prices. Just as offer mitigation for above-cost resources has been in every RPM tariff since first approved by the Commission, so too has a MOPR. Together, these paired rules align market prices with true marginal costs.

12. Efficient prices in a competitive market reveal the true societal costs of marginal supply, and thereby assure that demand is met by the lowest-cost supply. By contrast, if a supplier were allowed to offer capacity at any price above its costs, it could withhold economic capacity, raising both the market price and the total cost to serve load. Likewise, if supply can underbid its costs, costly supply resources can displace more efficient suppliers, again raising the cost to serve load and resulting in the inefficient, premature retirement of otherwise cost-effective resources.

13. Government policies always have the potential to move prices away from their efficient, competitive prices. Taxes, subsides and other policy tools affect both supply and demand, resulting in different market outcomes. Corporate income taxes, for example, increase the offer prices (but not the economic cost) of all supply, aside from public power and other untaxed entities. The effects of such general policy tools, however, do not meaningfully change the true, economic cost of meeting supply because they minimally reorder the supply stack.[7] But when a policy singles out a few resources for special subsidies, shifting some portion of the economic costs of those resources from the

[7] I leave aside the impact of charges that assign prices to otherwise unpriced attributes, such as air emissions. Properly designed and uniformly deployed, such charges align the financial costs with the true economic costs of a supply resource.

competitive markets to government coffers, there is a clear reshuffling of the supply stack. Costly units now appear cheap; efficient resources are squeezed out of the market; and wholesale price no longer reflect the true costs of serving load. Moreover, allowing selective subsidies to lower wholesale market prices impairs the opportunity of competitive suppliers to recover their investments, made in the reasonable reliance that prices will reflect marginal costs.

14. The MOPR operates symmetrically to resource offer mitigation that prevents suppliers from distorting prices upward. The MOPR restores capacity prices to their competitive, cost-linked levels, even in the face of entry by subsidized resources. As originally crafted and approved the MOPR applied only to new, gas-fired generators. At the time, gas-fired generators were the focus both of state policies and plans of utilities (vertically integrated utilities, public power and cooperatives) to sponsor large-scale generation outside of the PJM market construct. Incumbent coal-fired and nuclear units were generally profitable at pre-fracking gas prices, and large-scale renewables were generally not economic and, because of their low net capacity factors, were relatively high-cost sources of capacity. Thus a narrow rule, looking only at new, gas-fired resources, was not unduly limited. Today, states have more complex resource subsidy policies that are no longer narrowly focused on new, gas-fired generation. Nonetheless, these policies have the very real ability to distort wholesale prices so that they do not reflect the efficient, competitive cost of marginal supply.

15. A substantial revision to the existing MOPR is needed so that PJM's capacity market continues to price capacity at competitive, cost-based levels. The Commission's Order contemplates an expanded MOPR that is applied much more broadly, finding that "While the Commission in 2011 accepted PJM's proposal for a MOPR limited to new natural gas-fired resources, the evidence put forward by PJM and the intervenors demonstrate that the price-distorting effects on wholesale capacity prices caused by resources that receive out-of-market support reach far beyond new natural gas-fired resources."[8] I concur with the Commission's finding that an "expanded MOPR, with few or no exceptions, should protect PJM's capacity market from the price suppressive effects of resources receiving out-of-market support by ensuring that such resources are not able to offer below a competitive price."[9] Competitive, efficient prices must reflect the societal costs of providing marginal supply to ensure efficient deployment of capital. Just as the Commission has accepted market monitoring rules that broadly preclude

[8] Order at P 150.

[9] Order at P 158.

resources from suppliers at prices above their costs that are likely to raise prices above their competitive levels, so too rules need to preclude below-cost offers sponsored by loads that are likely to lower prices below their competitive levels. Anything short of such a comprehensive, symmetric rule will undercut RPM's ability to produce competitive prices to support efficient, least-cost resource adequacy for the PJM's bulk power system.

16. Unfortunately, the version of MOPR that PJM has discussed most recently with stakeholders and, presumably, is filing contemporaneously with the Commission, falls short of this standard and does not go far enough to protect the markets. In particular, PJM has discussed a sweeping carve-out for "self-supply" resources, *i.e.* those offered by Vertically Integrated or Public Power Entities, subject to a net short/net long review "applied only to planned resources in that seller's portfolio."[10]

17. PJM proposes allowing Self-Supply Entities to offer capacity (within net short/net long bands) at any price. For net short entities that rely on the purchase of top-up capacity from the RPM, this exemption from the MOPR would allow them to benefit from the resulting market price suppression of below-cost offers. For net long entities, the exemption allows them to push uneconomic resources into the market, displacing lower-cost resources. This action would be profitable if the Self-Supply Entity, or its customers, would otherwise have had to bear the full cost of maintaining this uneconomic supply—the MOPR exemption would instead allow some of these costs to be shifted to consumers elsewhere in PJM.

IV. THE FRR ALTERNATIVE UNDERCUTS THE SOUND OPERATION OF THE MOPR

18. As proposed, the FRR Alternative functionally destroys MOPR in its entirety. A robust MOPR is necessary, however, to "protect PJM's capacity market from the price suppressive effects of resources receiving out-of-market support ...."[11] Without an Extended MOPR, as I discuss above, PJM's capacity prices will likely be pegged below the efficient, competitive level by the action of targeted subsidies by the states, rather than "the result of competitive market forces."[12] The Commission also recognized that the actions needed to ensure competitive pricing and all of the associated market efficiencies can also create a different form of inefficiency: excessive procurement of

[10] PJM "Proposal Including Stakeholder Input, 2018-09-11" available at: https://www.pjm.com/-/media/committees-groups/committees/mrc/20180911-special/20180911-pjm-proposal-including-stakeholder-input.ashx .

[11] Order at P 158.

[12] *Id.*

resources by customers, once through the PJM markets and a second time through out-of-market actions of a state or utility. As a potential remedy, the Commission proposed a "resource-specific FRR Alternative" that allows "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. ... Resources and load that take advantage of this new resource-specific FRR Alternative would not participate in the PJM capacity market, and neither would make nor receive payments from the capacity market."[13]

19. While I support, as a general matter, market reforms that balance the potentially conflicting needs for efficient pricing and accommodation of states' resource procurements, the FRR Alternative as sketched in the Order does not strike a reasonable balance between these two needs. To the contrary, as I read it, the FRR Alternative would completely undermine the proper functioning of the MOPR and thus the RPM.

20. Moreover, this impact on competitive prices is directionally the same as if the subsidized unit had been exempted from the MOPR entirely. See Figure 3 of Exhibit RBS-2. In this example, the demand curve is left unchanged from the competitive case, but the subsidized resource is granted a MOPR exemption and allowed to offer at zero, shifting the supply curve rightward. As with Figure 2, the result is a suppressed Resource Clearing Price.

21. Why would any subsidized resource subject to MOPR *not* elect the FRR Alternative? Some subsidized resources may be economic even at their full, unsubsidized costs and so would expect to clear the BRA even at their MOPR-imposed cost-based offer. These resources, therefore, would logically not use the FRR Alternative, clear the BRA, and receive a capacity payment. For resources whose true, unsubsidized costs are *above* the expected Resource Clearing Price in the BRA, however the choice is between electing the FRR Alternative and receiving no capacity payments, or being subject to the MOPR, not clearing the BRA, and receiving no capacity payments. While this resource doesn't receive any capacity payment in either case, as an FRR Alternative Resource its matched load also no longer has to pay for that capacity through PJM settlement. For resources in a vertically integrated utility's portfolio, this is a direct win. For other subsidized resources, some change in the subsidy level or bilateral contract with load will be needed to transfer some or all of the consumer savings to the supplier. We can see, therefore, that the FRR Alternative renders MOPR into a nullity: the only resources that would be

[13] Order at P 160.

subject to MOPR would be those for whom the MOPR had no effect, and conversely all resources expecting to be adversely affected by the MOPR could profitably opt out of this offer mitigation by choosing FRR Alternative status. Notwithstanding the Commission calling for "an expanded MOPR, with few or no exceptions"[14], the FRR Alternative makes the MOPR optional for any resource—exactly the opposite of "few or no exceptions."

IV.A. Allowing subsidized new entry to distort Resource Clearing Prices undercuts the economic basis for RPM

22. In approving the original RPM design, PJM provided carefully calibrated models, prepared by Benjamin J. Hobbs, the Theodore M. and Kay W. Schad Professor of Environmental Management at the Johns Hopkins University Whiting School of Engineering and the Chairman of the Market Surveillance Committee of the California Independent System Operator. Prof. Hobb's analysis, submitted by PJM in support of the RPM settlement agreement, examined how the shape of the Variable Resource Requirement affects the level and variability of prices over time, built on the assumption that efficient new generators will be added, when and where needed, to maintain resource adequacy as load grows and older units retire. Low prices created by short-lived oversupply from new entry and stochastic shocks to demand must balance high prices during periods of relative scarcity, and the financing cost of new construction depends in part on the degree of variability of prices. This model showed clearly that a sloped demand curve reduces consumers costs, both by lowering financing costs but also by reducing energy prices, principally by reducing the frequency of shortage pricing.

23. A critical component of Prof. Hobbs' analysis supporting RPM was that new capacity resources are reliant solely on market revenues and—critically—expect the path of future capacity prices *also* to reflect unsubsidized future entry. The capacity price required by a rational supplier to build new capacity reflects not only the price in that first BRA, but also the expectation of all BRAs throughout the economic life of the resource. If future capacity prices are highly volatile or could fall easily to low levels, then the first-year offer price for new capacity rises accordingly to balance out that risk. The equilibrium in his model, and on which the RPM design is premised, is that the market moves to a balance where new entry is needed, and occurs, in most years, and the capacity prices hover within a fairly narrow band around the Net Cost of New Entry ("Net CONE"). Although a developer knows that its offer price for new capacity could only set prices for, at most, one year, it can build a fairly small market risk premium into its offer under the

[14] Order at P 158.

reasonable expectation that, in the future, offer prices from similarly situated, competitive suppliers will generally set the market clearing price.

24. While the Hobbs model did not model how subsidies to capacity would affect the market, it is not a difficult thought experiment. PJM requires approximately 165 GW of capacity resources. Peak load growth is low, about 1 percent, indicating that about 1.65 GW of new resources are needed to meet load growth. Additional demand for new resources is created by retirement of older units. If the economic lifetime of capacity resources is 50 years, then on average 2 percent, or 3.3 GW, retire each year. In fact, capacity deactivations in PJM averaged 2,505 MW annually from 2003–2018 and 3,180 MW annually from 2009–2018. Thus there is an average annual requirement for about 5 GW of new resources to offset peak load growth and unit retirement. The actual figure would, of course, vary from year to year, depending on load forecasts and planned retirements; on some years, no new capacity may be needed. If state subsidies, either to new or existing resources that would not otherwise be in the market, displace this amount (or more) of new supply requirements, then absent the action of an effective MOPR, capacity prices will be suppressed.[15] Although it may seem unlikely that 5 GW of subsidized resources would consistently be added, that argument misses a key point: the need for net new capacity fluctuates from year to year, and so any rule that allows subsidized capacity to displace market capacity runs the risk of suppressing capacity prices. The larger the tolerated subsidized entry, the greater the expected distortions to competitive pricing.

25. This price distortions affects the market not only in that one year but also ripples through all other years' BRAs. Market risk translates directly into higher prices through efficient capital markets. When market-based capacity resources face greater risks from poor market design, their cost of money rises, and so they must raise their offers into the capacity market. This creates a vicious circle: higher costs for market-based capacity and the associated supply reduction created by the risk of unmitigated state subsidies prompt states to take actions to address perceived market shortages or failures, spurring further rounds of subsidies. In short, if investors do not have confidence in the ability of the

[15] In the Hobbs model, the supply curve for new capacity was flat, so as long as *some* new capacity was economic at the market price, any amount of new capacity could enter. In the real world, there is not a knife-edge between new and existing resource costs. New development projects will have a range of costs, and some existing resources have going-forward costs that are higher than those of new projects. Consequently, displacing *any* market-based capacity with subsidized capacity will lower the capacity prices in that BRA and increase the required offer prices and market risk for competitive resources in all years.

market to function over time, then private investment is deterred and states will need to provide increasing rounds of subsidies.

IV.B. The FRR Alternative allows States to exercise of buyer-side market power

26. The original intent of the MOPR was to deter the manipulation of wholesale capacity and energy markets by state action. The original issue was the clear intent of several states to sponsor new, gas-fired generation in their states, even though existing resources were sufficient to meet reliability requirements. Had the states carried through with these plans, extra generation would have been built, removing binding constraints both in the capacity market and energy market. Relaxing these constraints then lowers wholesale prices in the state, though potentially raising prices in surrounding states. The MOPR, as originally implemented, prevents this sort of market power abuse by preventing subsidies to new, efficient resources that (a) the market could and should have brought forward and (b) should have been setting the Resource Clearing Prices when they enter the market.

27. The current rounds of state actions are—at least on their face—intended to achieve goals other than price suppression. This change does not justify sweeping exemptions to the MOPR created by the FRR Alternative.

28. First, it is hard to untangle whether the current round of policies are entirely benign in their intent. Keeping nuclear units operating is certainly one path towards lower carbon emissions or maintain local jobs, but in calculating the costs of these subsidies to ratepayers, any respectable policy analyst would include savings from capacity market price suppression that results, unless such suppression was not foreclosed by market design.[16] Thus potential price distortions relieve the state from bearing the full cost of its chosen policies, instead exporting some of those costs to neighboring states, competitive suppliers, or both.

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[16] I have not reviewed the supporting analysis for various Zero Emission Credit programs in PJM. In New England, however, the economic experts testifying on behalf of both Central Maine Power and the State of Maine Public Utility Commission calculated that capacity cost savings account for about two-thirds of the benefit to consumers of new transmission proposed in response to subsidized contracts offered by Massachusetts. My testimony in this matter notes that ISO New England's recent Forward Capacity Market tariff changes will eliminate or greatly reduce these purported savings. See *CENTRAL MAINE POWER COMPANY Request for Approval of CPCN for the New England Clean Energy Connect Consisting of a 1,200 MW HVDC Transmission Line from Québec-Maine Border to Lewiston (NECEC) and Related Network Upgrades*, MPUC Docket No. 2017-00232.

29. Second, regardless of the purity of intent of current state programs, the enormous loophole in the MOPR created by the FRR Alternative clearly invites new subsidies in the future whose primary intent is price suppression—exactly what the the MOPR was originally intended to foreclose. Such action would directly harm competitive suppliers and, potentially, consumers in neighboring states and, in the long-run, undermine the benefits to all consumers of a sound, stable wholesale market for capacity and energy.

30. The direct impact of allowing subsidized resources to set the clearing price is complex. In the simple case of an unconstrained market, allowing subsidized resources to offer at the bottom of the resource stack displaces the most costly, economic resources in the market, leading to price suppression. Consequently, competitive suppliers earn less than their competitive returns. When Capacity Emergency Transfer Limits bind or would have bound but for the unmitigated subsidized units, these subsidies may lower the capacity prices in the sponsoring state but *raise* them elsewhere. I discuss this case below at P 57 below. When these conditions arise, the subsidizing state is effectively exporting some of the subsidy cost to neighboring states.

IV.C. The FRR Alternative would create serious implementation problems and increases the potential of affiliate abuse.

31. As discussed in the Order, the FRR Alternative also creates several substantial implementation issues that compound the market design issues discussed above.

32. First, the FRR Alternative potentially creates serious issues with states who, by law or regulation, have opted to move to retail choice. In the existing FRR structure, this was never an issue for two reasons: first, because an entire control area had to shift to FRR and second, because FRR states are typically not retail choice states, which means that customers are generally ineligible to select alternative sources of retail electricity supply. In traditional FRR states, the process of matching load to supply was straightforward and there is no risk that federally imposed rules might interrupt the competitive retail environment. Matching load and generation is decidedly *not* straightforward under the FRR Alternative (or PJM's ReCO, discussed later). FRR Alternative resources are, by definition, receiving a subsidy. In addition to this subsidy, the subsidized resource would likely earn capacity revenues through bilateral contracts with load-serving entities.[17] Figure 1 below shows what I believe would be the normal structure of

[17] The subsidy was, presumably, structured assuming that the resource(s) would clear the BRA and receive capacity payments. To offset the loss of capacity revenues required by the FRR Alternative, or PJM's ReCO, the FRR Alternative Resource presumably needs to replace these capacity revenues from some source, likely a change in the subsidy rate (which would typically require legislative action) or through bilateral contracts with an LSE. See also P 21 above.

subsidies and contracts in a FRR Alternative world. Generally, the subsidy is collected via a non-bypassable surcharge,[18] but who receives the capacity credit for the bilateral capacity is a fraught question. If the customers paying the bilateral capacity contract charges are not the same customers receiving the credit for this capacity, FRR Alternative creates cross-subsidization among customers and an unlevel playing field at the retail level.

33. How this issue will manifest itself is a varied as the ways a state or utility might fund the bilateral capacity contract. A state may direct its electric distribution companies to enter into a bilateral capacity contract to subsidize a preferred resource and to charge its default supply customers the costs. If PJM simply reduces the capacity obligation for the utility's service area, however, then competitive retail suppliers will receive benefits of lower capacity prices without bearing the cost of the matched contract. Conversely, if a state funds the bilateral contract through a broad-based tax, but the electric distribution company is allowed to take all the resulting capacity credits, competitive retail suppliers will be at a cost disadvantage. This problem is particularly difficult to unpack when there is both a subsidy, provided by the state, and a power purchase agreement to, for example, sell energy and capacity to the local distribution company for its default load. This bifurcated situation makes it very challenging to determine who should enter into the capacity bilateral – the LDC or each individual LSE (of which there may be many in a retail choice state), as well as whether the capacity credits should flow back to LDC or LSE customers. It is also unclear how the Commission would force competitive LSEs to purchase, on a bilateral basis, capacity from the FRR Alternative resources. Requiring LDCs to contract is equally problematic. It is a substantial task for PJM to sort out these issues for each individual FRR Alternative resource and develop an equitable allocation of credits to load. Depending on the nature of the funding, it may require PJM to shift the allocation within a month as retail customers shift to, from, or between competitive retail suppliers. This level of settlement complexity was one reason why the current FRR design can only be elected for an entire control area and in areas outside of retail choice states. It also raises the question of which entities should be charged with the development and operating costs of the additional settlement processes required by the FRR Alternative.

[18] Usually, but not always. For example, Massachusetts has recently structured its off-shore wind procurement as a bypassable charge.

Figure 1a: Current cash and product flows

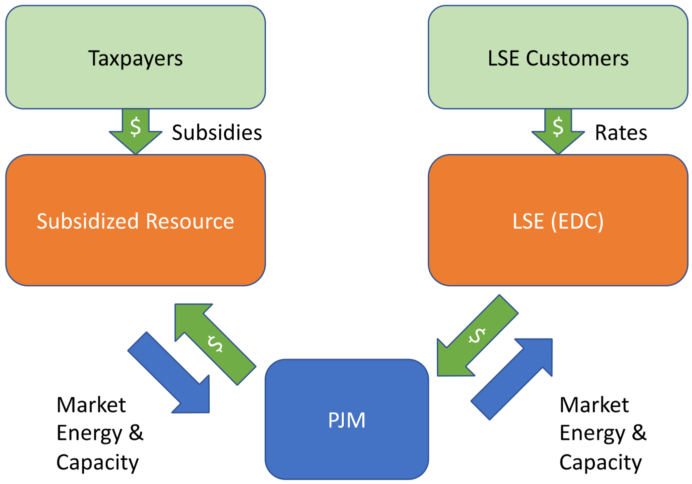
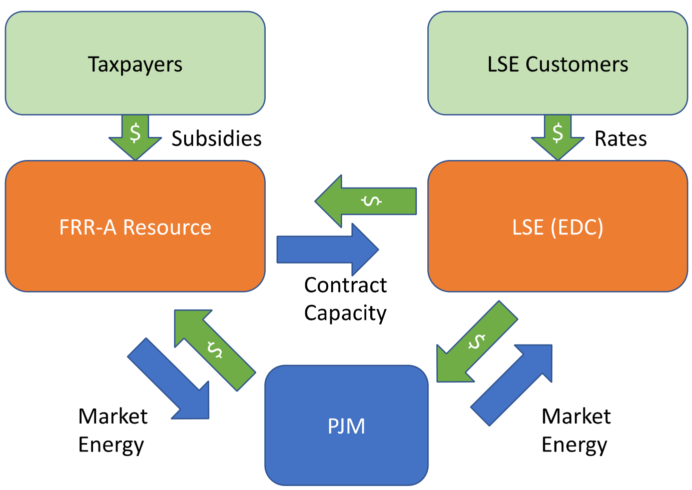


Figure 1b: Possible FRR Alternative flows



34. A second and potentially related issue is raised when, in a state with competitive retail options, the FRR Alternative resource is owned by the local distribution company or an affiliate. By stepping outside of markets and competitive prices, FRR-A contracts create an opportunity for regulated utilities to enter into above-market contracts with their

affiliates to the detriment of the market. This could occur in several ways. First, the LDC could engage in good old-fashioned affiliate abuse by entering into high priced contracts with their profit-seeking generator affiliate and passing through those excess costs to captive customers. A second more subtle form of abuse could arise if bilateral capacity contracts are structured so as to allocate charges between capacity and energy in such a way as to disadvantage competitive suppliers. Or the state subsidy, funded by all ratepayers, may allow the power purchase agreement to be struck at below-market prices or other favorable terms for the affiliate utility. For example, if an above-market capacity credit was paid by subsidies broadly collected in a state, but an affiliated retailer was able then to contract for below-market energy from the subsidized supplier, it would be able to offer rates to competitive supply customers that unaffiliated retailers could not match. Generally, bilateral contracts are outside the purview of PJM and its market monitor, because they are assumed to be arm's length arrangements by two self-interested counterparties. But that is obviously not the case here, so the Commission would need to establish and enforce clear standards on FRR Alternative (or ReCO) contracts between affiliates. In particular, these contracts should not be granted review waivers based on the market-based rate authority of the affiliate. The MBR tests measure potential market power using metrics that are completely irrelevant to the question of whether affiliate purchases are, in fact, negotiated at arms-length and are consistent with competitive terms and conditions.

35. A third implementation issue is setting the precise quantity of load that is matched to a FRR-Alternative Resource. PJM should use, at a minimum, the applicable *realized* reserve margin in determining the amount of load that is matched to FRR-Alternative MWs. For example, if the BRA clears at a 20.5 percent reserve margin in the load zone of a 100 MW FRR-Alternative resource, then that resource should be matched with 100/120.5% = 83 MW of load. Exempting any larger quantity of load has an inequitable result, namely that the loads charged through the BRA pay for more of the market-cleared resources than they would had the FRR-Alternative not been applied. Suppose, for example, that instead of using the realized reserve margin of 20.5 percent, PJM applied the required reserve margin of 16 percent, then 86.2 MW of load would be excused from the capacity market, 3.2 MW more than is consistent with the auction clearing. But all the other cleared MWs need to be paid by someone, and spreading these unchanging costs among a smaller amount of load effectively raises the prices to loads not matched to FRR Alternative Resources. An even more extreme disparity arises if the Order's words are taken literally and a full 100 MW of load is matched to a 100 MW FRR Alternative Resource, implicitly placing *none* of the cost responsibility for the capacity

reserve margin on this load. This result would be contrary to the Commission's stated intent that this mechanism separate the results of the market and non-market outcomes.

36. While the *realized* reserve margin is a minimum equitable quantity, imposing a somewhat larger margin on these resources may be warranted. If the matched load quantity is fixed for the lifetime of carve-out nomination, which may be a preferred outcome when there is a paired bilateral capacity contract, then the matched load quantity should make it highly likely that the implied reserve margin for the load in future years is not lower than the market realization of that reserve margin. Furthermore, a higher reserve margin for FRR Alternative load is appropriate because they are implicitly relying on the whole system, not just their tagged FRR Alternative resources, to provide reliability, and the reliability of those tagged resources is likely to be lower than the aggregate reliability of the system.

IV.D. The reasonableness of FRR does not make the FRR Alternative reasonable

37. The existing FRR strikes a reasonable balance of protecting competitive pricing while accommodating supplier and state resource choices. In the original settlement agreement we carefully and narrowly crafted the FRR to require that a vertically integrated utility (whether public power or an investor-owned utility) take *full* responsibility for meeting its resource adequacy requirements without accessing the PJM capacity market, either to top up deficiencies or sell surpluses. This design was premised on the fact that most vertically integrated utilities have a balanced portfolio of resources and load, and that nearly all of those resources are economic—that is, they would have cleared in the capacity market had they been offered at cost. When that utility opts for FRR, removing its load and resource portfolio from the market, but because nearly all FRR supply resources would have cleared, the impact on market prices would be minimal. Moreover, because the utility's participation in the RPM was sharply limited, it could not directly benefit from any changes in the RPM clearing prices resulting from its FRR election. Collectively, these elements of the FRR design ensured that FRR election by a utility had a limited impact and created no incentives for the FRR Entity to make the election for the purposes of affecting capacity prices.

38. Although the FRR Alternative has a superficial resemblance to the FRR, it lacks the safeguards built into the FRR that create the balance between efficient pricing and reasonable accommodation.

39. While the FRR is fairly balanced because nearly all of a utility's resource portfolio is economic; consequently, removing these resources and the corresponding load have

little effect on the competitive clearing price. In sharp contrast, the FRR Alternative is explicitly intended for resources that are *not* economic. On a supply stack reflecting true costs, these FRR Alternative resources would be in the high-cost part of the stack that would not have cleared in the BRA. Removing them from the supply stack, therefore, leaves the relevant portion of the supply curve unchanged. But the FRR Alternative *also* contemplates removing a matching quantity of load, and this load would have cleared in the competitive BRA. The effect on prices is unambiguous: the FRR Alternative would lower competitive clearing prices. See Figures 1 and 2 of Exhibit RBS-2.

V. PJM'S RESOURCE CARVE OUT FAILS TO PROTECT COMPETITIVE MARKETS

40. PJM's ReCO is similar to the FRR Alternative in many respects. PJM's discussion of its planned filing suggests that ReCO will address, in whole or in part, some of the ancillary issues that I discuss in Section IV.C above. A proposal consisting solely of the Extended MOPR and ReCO fails to address the core issue with the FRR Alternative, which similarly afflicts ReCO: unfettered ability of buyers to manipulate RPM prices through state subsidies, to the detriment of the ability of the market to achieve its core goals, while allowing states to avoid paying the full costs of their subsidies, instead shifting costs to other states or to competitive suppliers.

41. Although, like its cousin the FRR Alternative, ReCO is fatally flawed without further market design changes, it improves upon the FRR Alternative in three narrow areas.

42. First, under PJM's proposal, ReCO resources and their matched load are left in the Base Residual Auction for the purposes of selecting resources as capacity suppliers. This approach forestalls several issues that would be caused by removing the resources and load prior to the auction:

    a. The VRR curves would have to be redrawn. The VRR curves reflect reliability assessments of the local areas. Adjusting them would be a complex process that was highly dependent on which particular resources were carved out.

    b. Resource selection and the resulting Resource Clearing Prices must reflect *total* resource commitments and their impact on capacity transmission limits between regions.

43. Second, resources electing a carve-out still take on a capacity obligation, are not paid the Resource Clearing Price, but *are* subject to performance penalties and bonuses. This approach is superior to withdrawing these resources from the capacity construct entirely because it provides the same financial incentives to carve-out resources and competitive

resources to offer high-quality resources to the market and to maintain and operate them so as best to support system reliability needs. In particular, if subsidized resources were able to avoid performance penalties, there is a risk that subsidies would begin to shift towards poorly performing generators, rather than to generators that meet some positive policy goal.

44. Third, PJM specifies that the ReCO, once elected, must last for the life of the subsidy. This fails to parallel the five-year commitment required under the current FRR option that properly limits the ability of a resource to earn the higher of cost or market. Life of subsidy is the *minimum* duration that forestalls such behavior. If, instead, a resource could make the carve-out election annually, it could opt out of the market clearing in years when capacity prices were below its subsidy payments, but then move back into the market when prices rise and the resource could clear based on its economics, thus giving the resource only market up-side.

45. Although a "life of subsidy" requirement is necessary, it is not sufficient protection against abuse. The timing of state subsidies may not (by chance or design) align well with the RPM schedule. A resource that is not today subsidized may well expect to become so by the beginning of the applicable Delivery Year. Likewise, a unit that is currently receiving subsidies under a program that requires periodic reauthorization may reasonably expect that reauthorization to occur but avoid the MOPR. In these and similar examples, the exact application of the Material Subsidy determination and the carve-out election period need to be considered together.

46. A further issue raised by the ReCO is what amount of load is matched with each resource. In the BRA each MW of load carries the cost of more than one MW of resource, creating a capacity reserve margin, which gives PJM an operating margin to ensure resource adequacy under a range of system operational states. Although PJM computes a *minimum* reserve margin, on which the Variable Resource Requirement curves are set, the *realized* reserve margin is determined by the actual clearing of the BRA. This realized reserve margin varies year to year and across each constrained Locational Delivery Area. The Order's suggestion that an equal amount of load and generation should be carved out for the FRR-Alternative would create discriminatory treatment of among loads.

47. The ReCO represents a significant accommodation to states' resource procurement policies. For the purposes of selecting capacity suppliers, the ReCO effectively exempts any subsidized resource from the MOPR, allowing them to be counted as capacity resources regardless of whether their true costs are higher than other, competitive resources offering in the BRA. This approach, therefore, fully addresses the

Commission's concern that consumers may be forced to "pay twice" for capacity: once through state procurements and again through PJM's capacity market. It does so at a significant cost, however, to the generation owners whose economic resources will be crowded out of the market by subsidized resources. On top of this substantial loss, this unlimited waiver of the MOPR would lower the Resource Clearing Price.

48. Consequently, although the ReCO encompasses several improvements in implementation of the FRR Alternative concept, as a standalone market reform it is still fatally flawed. State action will be left unchecked to influence capacity prices, crowding out efficient existing resources and private investment in new, efficient market-based resources, just as the FRR Alternative would.

49. PJM has, however, prudently offered two further mechanisms (a repricing approach combined with a calculation of lost opportunity costs) that together work to keep capacity prices at efficient, competitive levels and to provide reasonable compensation to resources that have been crowded out, while still fully accommodating the quantities of subsidized resources sponsored by the states.

VI. The goals of the FRR Alternative can be achieved through a package of market reforms

50. The FRR Alternative discussed in the Order, as well as the ReCO proposed by PJM, unwinds the market protections discussed in the Order from the MOPR, creates complex and administratively burdensome settlement issues, and raises the potential for affiliate abuse and the undermining of state's policies regarding competitive retail supply. For these reasons, I believe the Commission should adopt, as an integrated package and with minor adjustments, an alternative that combines the ReCO with a corrective counterbalance. This counterbalance could be in the form of the quantity prorationing that I have previously introduced or, potentially, using a form of price redetermination and Lost Opportunity Cost payments as introduced by PJM. While meeting the core goals laid out in the Order, either approach, taken as a whole and in combination with the strong MOPR I discuss above, strikes a better balance between accommodating state actions and preserving competitive wholesale markets.

VI.A. Quantity Prorationing to accommodate subsidized resources

51. In my prior affidavit on this subject, I discussed in detail a proposal to accommodate subsidized resources through a quantity prorationing of capacity awards. In summary, this approach works as follows:

- A strict MOPR is applied, as well as existing market monitoring on capacity offer prices to yield a supply stack using mitigated and competitive offers.

- The RPM is cleared, establishing zonal Resource Clearing Prices and initial awards of capacity commitments.

- Resources with offer prices below the applicable Resource Clearing Price, but whose MOPR-restated prices were above the RCP, may elect to take a Capacity Supply Obligation for some or all of their capacity. These resources do not receive, and matched load does not pay, the RCP.

- The initial awards from step (b) are reduced *pro rata* to accommodate the resources electing capacity status in step (c). This prorationing is allocated so as to ensure that inter-zonal Capacity Transfer Limits are not violated by the resulting set of capacity resources.

52. This approach ensures that the quantity and price from a fully competitive outcome are preserved, while allowing all state-sponsored and other subsidized resources to participate as capacity resources. Consumers would not "pay twice" for capacity. Resource suppliers collectively would receive lower payment than if no accommodation were made, but they also take on lower levels of Capacity Obligations. There are no "in-between" resources that are systematically crowded out of the market, but each resource would have some small, uncleared surplus capacity. This surplus could be consolidated within or transferred between companies, thus freeing resources to be offered as capacity in other markets or simply deactivated or put into reserve shutdown.

VI.B. PJM's Redetermination of the Resource Clearing Price

53. PJM proposes a different counterbalance to the ReCO to restore market integrity. In this proposal PJM would restate the Resource Clearing Price in conjunction with the ReCO. It also proposes paying the resulting "in-between" resources (those that were crowded about by accommodation) a Lost Opportunity Cost. Although I have not had the opportunity to review PJM's filing, this general approach may provide a reasonable alternative to my preferred approach of quantity pro-rationing.

54. This process would proceed in two stages. First, capacity obligations would be assigned to resources based on their offer prices, with the following exceptions:

    a. First, resources electing the ReCO would be treated as self-scheduled resources, effectively as if they had bid $0.

b. Second, resources not electing ReCO treatment but receiving a Material Subsidy would be subject to the expanded MOPR.

As I discuss above, however, in operation this clearing will act as though the MOPR did not exist, as any resource expecting to be excluded from clearing in the BRA by the MOPR would rationally opt for a ReCO. All subsidized resources, economic or otherwise, would be expected to clear, displacing an equivalent quantity of more efficient but market-based resources.

55. The second stage is to redetermine the Resource Clearing Price for each relevant Locational Delivery Area ("LDA") excluding the ReCO resources from the supply stack. Although this approach conforms to the Order's goal of separating the subsidized and competitive resources, it may overstate the true societal cost of securing adequate resources and, consequently, lead to higher prices than are just and reasonable. This problem arises when *some* of the ReCO resources would, at their MOPR-mitigated offer prices, have been economic when *all* ReCO resource offers are mitigated. This outcome is a consequence of "subsidies beget subsidies:" resources that would have been economic on their own in a fully competitive market may receive subsidies to protect them from being squeezed out of the market by uneconomic resources that receive subsidies. Therefore, instead of being fully excluded from the price redetermination stage, ReCO resources should be included in the price redetermination step at their MOPR-mitigated offer prices.

56. With that change, the supply curve will reflect full societal costs, and the resulting Resource Clearing Prices will be at their efficient, competitive levels, consistent with the underlying economic premises of the RPM design as embodied in the analytic model of Prof. Hobbs. While clearing prices would still vary as supply and demand conditions shifted, they would be insulated from the regulatory risk created by state action. These restated prices are then paid only to *competitive* resources that received a capacity obligation in the first stage. That is, ReCO units do not receive a capacity payment from the market.

57. I present the effect of this redetermination in a series of charts in Exhibit RBS-3. Figure 1 of that exhibit show for a simple, unconstrained system the two basic steps of clearing first quantity (left panel) and then determining price for non-ReCO resources (right panel).[19] Units shown with orange bars receive Material Subsidies and have opted for ReCO status, thus allowing them to receive capacity commitments in the first stage of the

[19] In this simple example, the modification to PJM's proposal I discuss in P 55 is not relevant.

BRA (left panel).[20] Having established capacity commitments, PJM then determines the Resource Clearing Price excluding the ReCO resources (shown in the figure at their mitigated offer levels). This may result in some resources with offer prices at or below the Resource Clearing Price but which do not receive a capacity commitment (shown as a hashed column in the right panel of Figure 1). I discuss these "between" units later.

58. More complex and counter-intuitive results can occur when capacity transfer limits between LDAs bind. Importantly, *which* interfaces bind can change between the first and second stages. An example of this possibility is given in Figures 2 and 3 of Exhibit RBS-3. Here I consider a hypothetical where the RTO-EMAAC interface is binding in both stages, limiting our focus on EMAAC and the potentially constrained PSEG (New Jersey) zone within EMAAC. Suppose hypothetically that the State of New Jersey has subsidized the Bivalve Bay Power Plant, a 1,000 MW resource in the PSEG zone, and that Bivalve Bay's owners elect ReCO status. When PJM constructs the supply curves in PSEG and EMAAC, treating Bivalve Bay as offering at $0, the PSEG LDA does not bind. See Figure 3. The Resource Clearing Price at this first stage is therefore the same throughout EMAAC.

59. PJM then moves to the redetermination stage, with the modification I propose above. Bivalve Bay's offer price is restated up to its unsubsidized cost, $600/MW-day, and the supply stack for the PSEG LDA is restated. See Figure 4. With this mitigated supply stack, the PSEG LDA now separates from EMAAC, which has the effect of *increasing* the Resource Clearing Price for the PSEG LDA but *decreasing* the price elsewhere in EMAAC. Thus, by mitigating offers from subsidized resources, Resource Clearing Price redetermination prevents New Jersey's hypothetical subsidy from raising consumer costs in neighboring states. In this example without this redetermination, New Jersey ratepayers are enjoying below-cost capacity from the market, at the expense of consumers in Maryland, Pennsylvania and elsewhere.

60. Units electing the ReCO receive capacity obligations but no capacity payments from PJM.[21] Absent any other change in the tariff, this feature of the ReCO would create a settlement surplus at PJM because it is collecting capacity charges from all load but

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[20] For clarity, ReCO resources are shown with a $20 offer; as proposed, they would be self-scheduled, effectively entered at an offer price of $0.

[21] These resources are, however, subject to performance bonuses and penalties. Because these bonuses and penalties are self-funding among all resources, however, these payments or credits do not affect this discussion of the settlement surplus.

paying only a subset of capacity resources. For reasons I discuss below, this settlement surplus should be allocated as:

c. First, as Lost Opportunity Costs to competitive resources that were economic when all resources were considered at cost (stage two) but were displaced from the market because of ReCO elections (stage one). In earlier filings, these resources were often called the "between" resources. The Lost Opportunity Cost is calculated as the positive difference between the final Resource Clearing Price and a "between" resources offer price in the BRA.

d. Second, as a capacity credit to consumers who fund the subsidies associated with ReCO resources.

61. Paying Lost Opportunity Costs to "between" resources is vital to maintain incentives for resource owners to reveal their costs in their bids—a hallmark of good market design. The logic here is exactly the same as the logic supporting Lost Opportunity Cost payments in PJM's energy and ancillary services markets. A "between" supplier has capacity on offer at a price that is below the Resource Clearing Price. If Lost Opportunity Costs were not paid, then, anticipating its "between" status if offered at cost, the supplier has an incentive to offer *below* its cost, clear the market, and then receive a capacity price *above* its cost. But now the supply stack is reordered, and other economic suppliers perceive a risk that they will be the ones tagged as "between," so they in turn lower their offer prices to keep their spot in the capacity market. In this situation, the selected capacity suppliers are no longer necessarily the least-cost suppliers but those with the most aggressive bidding strategy—which is not at all consistent with competitive, efficient market outcomes. Instead, offering Lost Opportunity Cost leaves a "between" resource indifferent between (a) being a capacity resource and being paid the restated Capacity Resource Price or (b) not being a capacity resource and being paid its Lost Opportunity Costs. Consequently Lost Opportunity Cost payments restore the normal competitive pressures to bid truthfully and preserve efficient market outcomes.

62. Paying Lost Opportunity Costs to "between" resources preserves the correct competitive incentives for all unsubsidized suppliers to offer their resources at cost. These "between" resources would therefore receive the same *profit* from the capacity market as they would had subsidized resources not been accommodated, but not the same *revenues*. Consequently, because they did not receive their going-forward costs from the market, owners of these "between" resources may well choose to retire or mothball the resource, eliminating uneconomic surpluses in the market. The remaining portion of the

settlement surplus is returned to load on a "surplus causation" basis, crediting loads who have cost responsibility for the carved-out resources.

63. This concludes my testimony at this time.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Calpine Corporation, *et al.* v. PJM Interconnection, L.L.C.	Docket Nos. EL16-49-000
PJM Interconnection, L.L.C.	ER18-1314-000 ER18-1314-001
PJM Interconnection, L.L.C.	EL18-178-000 (Consolidated)

AFFIDAVIT OF ROBERT B. STODDARD
ON BEHALF OF NRG POWER MARKETING LLC

I, Robert B. Stoddard, being duly sworn, depose and state that the contents of the foregoing Affidavit on behalf of NRG Power Marketing LLC is true, correct, accurate and complete to the best of my knowledge, information and belief.

Robert B. Stoddard

SUBSCRIBED AND SWORN
before me this 2 day of October, 2018

Notary Public

My commission expires: 10|13|22

HANNA DANIEL
Notary Public, Maine
My Commission Expires October 13, 2022

Robert B. Stoddard

Principal, Power Market Economics LLC
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Amherst College

Robert Stoddard has over thirty years of experience assisting clients in defining, analyzing, and interpreting the economic issues involved with competition and product valuation in energy markets. As CEO of GWave, Robert provides executive leadership for a technology startup developing a new generation of ocean wave energy converters. He has raised over $30 million in 2016 to construct and test the first full-scale prototype, secured contracts, a berth site and all regulatory licenses for its first commercial installation, and managed an extensive supply chain designing and fabricating the prototype. He recently completed a licensing agreement to commercialize the technology.

Prior to joining GWave, Robert led the energy practice at Charles River Associates, a global consultancy. His work there focused on electricity industry restructuring, capital investment in power markets, and on providing both strategic analyses and testimony for utilities, generation owners, and governments regarding the practical implications of market design and structure, particularly of Regional Transmission Organizations. He has frequently testified to the Federal Energy Regulatory Commission as well as to the utility commissions and legislatures on competitive market design, rates, and market power issues.

Clients

Mr. Stoddard has been an expert witness or consultant on electric market issues to many leading law firms and to a wide range of energy market stakeholders including ArcLight Capital Management, AES, American Wind Energy Association, Astoria Generating, Babcock & Wilcox, Bangor Hydro Electric, California Independent System Operator, Citibank, City of New York, Connecticut Department of Public Utility Control, Consolidated Edison Co. of New York, Constellation Energy Commodities Group, CSG Investments, Dayton Power & Light, Devon Canada, Dominion, Duke Energy, Edison Mission Energy, EdF, Electricity Supply Board of Ireland, Emera, Energia dos Portugal, Energy Capital Partners, Energy East, Entergy Nuclear, FirstEnergy, FirstLight, GenOn, Hydro Québec, Independent Energy Producers Association, IGS Energy, International Power, J. Aron & Company, King Street Capital Management, Maine Energy Recovery Co., Maine Public Service, Midlands Cogeneration Venture, Morgan Stanley Capital Group, Morris Energy Group, New England Power Generators Association, New York City Economic Development Corporation, New York Energy Buyers Forum, NextEra Energy Resources, North American Energy Alliance, Northeast Utilities, NRG Energy, Orange & Rockland Utilities, Pepco Energy Services, Pinnacle West, PJM Power Providers, Portland General Electric, Powerex Corporation, Rhode Island Speaker and the House of Representatives, San Diego Gas & Electric, Sithe Global, Southern California Edison, Sunoco, Tenaska, Tonbridge Power, USGen New England, USPowerGen, and Williams Power.

Electricity market design

- Project director and testifying expert for capacity market design litigation and settlement negotiations for the New England and PJM markets, representing coalitions of the major generation owners in the region.
- Principal author of SDG&E and California Forward Capacity Market Advocates' proposal for a centralized capacity market structure to address resource adequacy needs of the California electricity markets. Subsequently offered a market-based approach to backstop capacity pricing in California on behalf of NRG Energy and the Independent Energy Producers Association.
- In the redesign of the wholesale power market for the Republic of Ireland, responsible for development of rules regarding demand-side integration, interconnection management, financial transmission rights, and transmission loss representation.
- Testifying expert on behalf of a major importer into the California electricity market on the allocation of financial transmission rights across external interties.
- Project director for a review for the California Independent System Operator of transmission rights allocations in the proposed California wholesale market.
- Principle drafter of the current form of the utility restructuring laws in Rhode Island, implementing improved retail market access.
- Project director for a major policy initiative by a major generation owner to review key flaws in modern RTO design that distort competitive pricing and outcomes.
- Project manager and testifying expert for litigation regarding the market rules governing use of phase angle regulators between New York and PJM. Subsequently, assisting the negotiated design of these rules pursuant to the FERC orders.
- Working with other CRA experts, prepared a white paper on capacity market design for Energia dos Portugal.

Market power analysis and mitigation

- Testifying expert successfully defending against charges of market manipulation by largest capacity importer to New England.
- Led preparation of report successfully defending against charges of market manipulation by a power marketer scheduling transactions through multiple jurisdictions.
- Lead expert defending a major financial institution against charges of manipulating ICE index markets (ongoing).
- Lead economist in team developing alternative mitigation measures for buyer-side market power in the New England capacity market.
- Testified on appropriate metrics for market power in PJM energy and capacity markets.
- Testified as to vertical and horizontal market power issues related to affiliation of merchant generation and the host distribution utility.

- Testifying expert and project director supporting the integration of Virginia Electric and Power (Dominion) into the PJM marketplace.
- Project manager for an acquisition of generation assets in Connecticut by a competing supplier, using detailed hourly analyses of power flows and potential future competition, and presenting the results to the FERC, US Department of Justice, and the Connecticut Office of the Attorney General.
- Project manager for a market power analyses needed to obtain federal and state regulatory approval of the merger of the leading natural gas transporter and distributor in the eastern US with a vertically integrated utility with substantial gas holdings.
- Project manager for study of the potential competitive effects of the divestiture of substantially all the New York City utility generation to independent power producers, including detailed behavioral modeling that took account of the complex transmission system and design of market power mitigation measures for the energy and capacity markets.

Strategy

- Led creation of business model and market-entry strategy for company developing an innovative renewable power technology.
- Led creation of business model and business plan for a combined wind-farm / transmission company in Canada.
- Assisted major utility in strategic and tactical plan to support transfer between Regional Transmission Organizations, providing both analytic and regulatory advisory support.
- Directed the development of the master energy infrastructure strategy for the City of New York, working with key stakeholders to develop a strategy to develop the infrastructure needed to meet the city's future energy needs economically and reliably.
- Developing a detailed forecasting model for capacity prices in PJM resulting from the new capacity market design and, using this information, worked with a major market participant's strategy and financing staff to identify under-valued assets for acquisition.
- With senior management of a major utility, developing a transmission investment strategy to reflect shifting competitive opportunities, RTO market design, and state and federal regulation. Identifying of key opportunities to leverage and redirect capital expenditures to significantly decrease cost of delivered power and increase rate of return to corporate shareholders.
- Developing a competitive bidding strategy for a complex hydroelectric generation asset to recognize opportunity costs, limitations of market rules, and effects of key transmission constraints in a two-settlement, locational pricing regime.
- Assisting a leading provider of utility outsourcing services to develop a comprehensive regulatory strategy for its service offerings to a major utility.

Electricity contracts and project valuation

- Reports to support long-term contracts with critical new generation facilities in Massachusetts.

- Testimony (in progress) to support the tax valuation of independent power production facilities in New York and Maryland, evaluating the free cash flows from sales of energy and other products' net of fuel, emissions, and other relevant costs.
- Testimony successfully supporting claims against industrial customer in breach-of-contract claims by a retail energy provider.
- Testimony supporting the cost-effectiveness of a long-term power purchase agreement between Cape Wind and National Grid in furtherance of Massachusetts policy goals.
- Testimony regarding the market value of a nuclear power facility excluding idiosyncratic nuclear risks using a comparable transactions analysis.
- Expert testimony supporting the reliability must-run (RMR) applications of over 2 GW of generation in New England, documenting need for RMR contracts to maintain the financial viability of needed resources. The case resulted in a settlement agreement that provided for significant support payments for these resources during the transition to compensatory market payments.
- Testimony for a bankruptcy court regarding damages arising from a power purchase agreement that had been rejected at the time of bankruptcy.
- Testimony in arbitration proceedings to determine the product specification and price of the capacity product contracted for in a period of regulatory change.
- Support of project financials for major purchase of New York City generation to investor community.
- Testimony in arbitration proceedings about the interpretation of, and damages owed under, the electricity section of a contract for the purchase of a large petrochemical refinery and resale of the refinery's output.
- State-appointed auditor of Connecticut's utilities' first Standard Offer power procurement auction, reviewing reasonableness of pricing and the terms and conditions of contract offers to supply essentially all of the state's power needs for a three-year period.
- Testimony on fuel costs adders reasonably allowable in a long-term power contract between NRG and Connecticut Light & Power and attendant retail rate design to fairly allocate the incremental costs.
- Assisting Consolidated Edison Co. of New York negotiate the sale of its nuclear facilities and linked buyback of power for the license life of the units.
- Working with Pinnacle West staff to develop options-based contracts to transfer power between its generating, trading, and distribution affiliates to preserve appropriate performance incentives.
- Project manager for bankruptcy evaluation of a New England cooperative, involving assessment of value of hydroelectric, nuclear assets, and long-term contracts.

Articles

With Richard D. Tabors and Scott Englander, “Who’s on First? The Coordination of Gas and Power Scheduling,” *Electricity Journal*, Vol. 25, No. 5, June 2012, pp. 9-15.

With Richard D. Tabors, “The Confluence of Utility Regulation: Water, Electricity and Natural Gas,” paper delivered at the 2012 Eastern Conference of the Center for Research in Regulated Industries at Rutgers University.

With Edward L. Kim, Richard D. Tabors and Todd E. Allmendinger, “Carbitrage: Utility Integration of Electric Vehicles and the Smart Grid,” *Electricity Journal*, Vol. 25 No. 2, March 2012, pp.16–23.

With Richard D. Tabors, “Flaws in Reliability Options as a Mechanism for Resource Adequacy: Evidence from New England,” paper delivered at the 2011 Eastern Conference of the Center for Research in Regulated Industries at Rutgers University.

With Harry Foster, “Optimal Pricing of Energy-Limited Resources in Capacity Markets,” paper delivered at the 2009 Eastern Conference of the Center for Research in Regulated Industries at Rutgers University.

With Seabron Adamson, “Comparing Capacity Market and Payment Designs for Ensuring Supply Adequacy,” Proceedings of the 42nd Hawaii International Conference on System Sciences, 2009.

Testimony and reports

CENTRAL MAINE POWER COMPANY Request for Approval of CPCN for the New England Clean Energy Connect Consisting of a 1,200 MW HVDC Transmission Line from Québec-Maine Border to Lewiston (NECEC) and Related Network Upgrades, State of Maine Public Utilities Commission Docket No. 2017-00232. Surrebuttal testimony on behalf of NextEra Energy Resources critiquing claimed capacity market benefits of the proposed transmission project. August 2018.

CXA La Paloma, LLC v. California Independent System Operator Corporation, FERC Docket No. EL18-177-000. Affidavit on behalf of the NRG Companies on the need for FERC action in restructuring the CAISO resource adequacy procurement process. August 2018.

PJM Interconnection, LLC, Docket No. ER18-1314-000. Affidavit on behalf of the NRG Companies assessing PJM’s proposals for reforms to its capacity market to accommodate subsidized resources. May 2018.

Grid Resilience in Regional Transmission Organizations and Independent System Operators, FERC Docket No. RM18-7-000. Design basis document for a Secure Energy Market to achieve resilience goals using markets, filed in comments of NRG Energy. May 2018.

Grid Reliability and Resilience Pricing, FERC Docket No. RM18-1-000. Affidavit on behalf of PJM Power Providers calling for meaningful reforms in PJM’s energy markets to ensure proper price formation to guard against premature retirements and other inefficiencies, November 2017.

PJM Interconnection, L.L.C., FERC Docket No. ER13-535-000. Affidavit in support of NRG Energy protesting proposed changes to the Minimum Offer Price Rule in PJM’s Reliability Pricing Model, December 2012, reply affidavit March 2013, affidavit on remand November 2017.

State Policies and Wholesale Markets Operated by ISO New England Inc., New York Independent System Operator, Inc., And PJM Interconnection, L.L.C., FERC Docket No. AD17-11-000. Prefiled comments "RTO Markets Must Change to Accommodate State Policies", April 2017, and invited remarks at FERC Technical Conference, May 2017.

California Independent System Operator Corporation, FERC Docket No. ER13-550-000. Affidavit in support of the NRG Companies and the Dynegy Companies, protesting the creation of a Flexible Capacity and Local Reliability Resource Retention Mechanism in lieu of a comprehensive market structure for resource adequacy, January 2013.

GenOn Bowline, LLC v. Town of Haverstraw, et al., Index No. SU-2009-6850 Hudson Valley Gas Corporation. v. Town of Haverstraw, et al., Supreme Court of the State of New York, County of Rockland, Index No. SU-2009-6860. Report projected energy and capacity revenues, March 2013; testimony January 2014.

"Analysis of the Impact of Salem Harbor Repowering on New England Air Emissions," CRA report authored by Mr. Stoddard on behalf of Footprint Power Salem Harbor Development LP, Massachusetts Electric Facilities Siting Board Docket 12-2, November 2012.

Capacity Deliverability Across the Midwest Independent Transmission System Operator, Inc./PJM Interconnection, L.L.C. Seam, FERC Docket No. AD12-16-000. Affidavit supporting comments of Duke Energy Corporation, August 2012.

In the matter of, on the Commission's own motion, to initiate a proceeding to establish a state compensation mechanism for alternative electric supplier capacity in Indiana Michigan Power Company's Michigan service territory, MPSC Case No. U-17032. Testimony on behalf of FirstEnergy Solutions Corp. supporting use of RPM capacity pricing retail rates, July 2012.

In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company For Authority to Provide for a Standard Service Offer Pursuant to R.C. § 4928.143 in the Form of an Electric Security Plan, PUCO Case No. 12-1230-EL-SSO. Rebuttal testimony on behalf of Applicants supporting reasonableness of multi-year contracts to hedge price risk, June 2012.

In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to §4928.143, Ohio Rev. Code, in the Form of an Electric Security Plan, PUCO Case No. 11-346-EL-SSO *et al*. Testimony on behalf of FirstEnergy Solutions Corp. supporting use of RPM capacity pricing in retail rates. May 2012.

In the Matter of the Commission Review of the Capacity Charges of Ohio Power Company and Columbus Southern Power Company. PUCO Case No. 10-2929-EL-UNC. Testimony and deposition on behalf of FirstEnergy Solutions Corp. supporting use of market pricing for capacity, April 2012.

"Update to the Analysis of the Impact of Cape Wind on Lowering New England Energy Prices," CRA report authored by Mr. Stoddard, on behalf of Cape Wind Associates, LLC, filed in *Petition of NSTAR Electric Company for Approval of a Proposed Long-Term Contract for Renewable Energy with Cape Wind Associates, LLC Pursuant to St. 2008, c. 169, § 83,* March 2012.

FirstEnergy Solutions Corp. & Allegheny Energy Supply Company, L.L.C. v PJM Interconnection, L.L.C., FERC Docket EL12-50-000. Affidavit in support of complaint seeking to require allocation of partial-year Auction Revenue Rights, March 2012.

California Independent System Operator, Inc., FERC Docket No. ER12-897-000. Affidavit in support of protest by NRG Energy, Inc. of proposed waiver of provisions of the Capacity Procurement Mechanism, February 2012.

FirstEnergy Solutions Corp. & Allegheny Energy Supply Company, L.L.C. v PJM Interconnection, L.L.C., FERC Docket EL12-19-000. Affidavit in support of complaint seeking to fund Financial Transmission Rights solely from Day-Ahead Market settlement surplus, December 2011.

"Resource Adequacy in Ohio's Restructured Market," CRA report authored by Robert B. Stoddard, on behalf of Duke Energy Ohio, December 2011.

Bangor Hydro Electric Company and Maine Public Service Company Request for Exemptions and Reorganization Approvals, Maine Public Utilities Commission Docket No. 2011-170. Rebuttal testimony on behalf of Emera regarding potential horizontal and vertical market power issues of proposed acquisitions, September 2011; live testimony, December 2011, March 2012.

PJM Interconnection, L.L.C., Duke Energy Ohio, Inc. and Duke Energy Kentucky, Inc., FERC Docket No. ER12-91-000. Affidavit on behalf of Duke providing cost-benefit analysis of its proposed transition from MISO to PJM in support of inclusion of transition costs in transmission rates, October 2011; rebuttal affidavit, November 2011.

In the Matter of Portland General Electric Company 2012 Annual Power Cost Update Tariff (Schedule 125), Oregon Public Utilities Commission Docket No. UE-228. Rebuttal testimony on behalf of Portland General Electric assessing reasonableness of its mid-term hedging strategy for gas and electricity procurement, August 2011.

California Independent System Operator Corporation, FERC Docket No. ER11-2256. Affidavit on behalf of the Independent Energy Producers Association protesting flawed elements of the Capacity Procurement Mechanism, December 2010; presentation to FERC Technical Conference, March 2011.

Expert Report on behalf of Mirant Mid-Atlantic, LLC, Maryland Tax Court Case Nos. 09-RP-CH-261-265; 09-RP-CH-280-294; and 09-RP-CH-294-298, July 2010; live testimony, February 2011.

PJM Interconnection, LLC, FERC Docket No. ER11-2288. Affidavit on behalf of GenOn Energy Management, LLC and Edison Mission Energy protesting the creation of a summer-only demand resource capacity product and the continuation of a limited demand resource capacity product in the PJM Reliability Pricing Model, December 2010.

Testimony on behalf of the PJM Power Providers before the Maryland Public Service Commission in Administrative Docket PC22 regarding the PJM Reliability Pricing Model and the 2013/2014 Delivery Year Base Residual Auction Results, October 2010.

ISO New England Inc. and New England Power Pool, FERC Docket No. ER10-787-000, and *New England Power Generators Association v. ISO New England, Inc.*, FERC Docket No. EL10-50-000 (combined). Affidavit on behalf of New England Power Generators Association supporting need for revisions to Forward Capacity Market design, March 2010. Rebuttal affidavit, April 2010. Pre-filed testimony, July 2010; supplemental affidavits, September 2010.

Maryland Tax Court Case Nos. 09-RP-CH-261-265; 09-RP-CH-280-284; and 09-RP-CH-294-298. Expert report projecting energy and capacity revenues for Mirant Mid-Atlantic Morgantown facility, July 2010; live testimony Feburary 2011.

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Richard Blumenthal, Attorney General for The State of Connecticut v. ISO New England Inc., Brookfield Energy Marketing Inc., et al. FERC Docket No. EL09-47-000, and *The Connecticut Department of Public Utility Control and the Connecticut Office of Consumer Counsel v. ISO New England Inc., Brookfield Energy Marketing Inc., et al.*, FERC Docket No. EL09-48-000. Prefiled testimony on behalf of Brookfield Energy Marketing Inc. regarding scheduling of capacity imports. June 2009. Answering testimony, February 2010.

Pepco Energy Services, Inc. v. Constellation Energy Commodities Group, Inc. (ad hoc arbitration); expert report on behalf of Constellation on alleged mis-payment under a bilateral contract for PJM capacity, April 2008; testimony, October 2009.

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California Independent System Operator Corporation, FERC Docket No. ER09-589-000. Affidavit on behalf of Powerex Corp. regarding changes to the CAISO credit policy regarding unsecured credit, February 2009.

"Contracting and Investment: A Cross-Industry Assessment" report filed with Post-Conference Comments of Reliant Energy, Inc., *Credit and Capital Issues Affecting the Electric Power Industry*, FERC Docket No. AD09-002-000, January 2009.

PJM Interconnection, LLC FERC Docket No. ER09-412-000. Affidavit and reply affidavit on behalf of Mirant, Edison Mission Energy, International Power, and FPL (NextEra Energy Resources) regarding omnibus changes to the PJM RPM capacity market tariff, January 2009.

Midwest Independent System Transmission Operator, Inc. FERC Docket Nos. ER08-394-000, -003, -007. Affidavit on behalf of Duke Energy protesting the market monitoring standards proposed for the voluntary capacity auction in Midwest ISO, January 2009.

Devon Canada Corp. et al. v. Pittsfield Generating Company LP et al. Expert report for defendant regarding damages from alleged breach of natural gas supply contract to a reliability must-run electric generator, December 2008.

Maryland Public Service Commission v. PJM Interconnection, LLC, FERC Docket Nos. EL08-34-000 and EL08-47-000. Affidavit on behalf on Mirant Parties on appropriate structural and behavioral market power tests in PJM, October 2008; reply affidavit, November 2008.

ISO New England, Inc., FERC Docket No. ER08-1209-000. Affidavit on behalf of the New England Power Generation Association on compensation to reliability resources, July 2008; reply affidavit, September 2008.

Midwest Independent Transmission System Operator, Inc. FERC Docket No. ER08-1169-000. Affidavit on behalf of FPL Energy, LLC, regarding revisions to Generation Interconnection Procedures, July 2008.

RPM Buyers v. PJM Interconnection, LLC, FERC Docket No. EL08-67-000. Affidavit on behalf of PJM Power Providers opposing *ex post* changes to initial RPM auction results, June 2008.

Assessment of Maine's Continued Participation in ISO New England and Alternatives, Expert report in Maine Public Utilities Commission Docket No. 2008-156, prepared on behalf of Bangor Hydro-Electric Company, June 2008; testimony to the MPUC, October 2008.

"Reliability at Stake: PJM's Reliability Pricing Model" report prepared for PJM Power Providers in conjunction with FERC technical conference to discuss the operation of forward capacity markets in New England and the PJM region, FERC Docket No. AD08-4-000, May 2008.

Estimation of Indian Point 2 Fair Market Value Using a Statistical Analysis of Comparable Transactions, Testimony in *Consolidated. Edison Co. of New York v. United States*, No. 04-0033C (Fed.Cl.), February 2008.

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Midwest Independent Transmission System Operator, Inc. Electric Tariff Failing Regarding Resource Adequacy, FERC Docket No. ER08-394-000. Affidavit on behalf of Duke Energy Corp. and FirstEnergy Services Co. on the urgency of implementing a uniform resource adequacy requirement, January 2008.

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In the matter of the application of Midland Cogeneration Venture Limited Partnership for the Commission to eliminate the "availability caps" which limit Consumers Energy Company's recovery of capacity payments with respect to its power purchase agreement with Midland Cogeneration Venture Limited Partnership, Michigan P.S.C. Case No. U-15320, testimony analyzing the relative economics of petitioner's facility to support the waiver. September 2007.

Wholesale Competition in Regions with Organized Electric Markets, FERC Docket Nos. RM07-19-000 and AD07-7-000. Affidavit on role of demand-side resources in organized electric markets on behalf of Duke Energy Corp., September 2007.

Order Instituting Rulemaking to Consider Refinements to and Further Development of the Commission's Resource Adequacy Requirements Program, California PUC Rulemaking 05-12-013. Principal author of SDG&E Track 2 Resource Adequacy Program Proposal, March 2007; principal author, "Joint Pre-Workshop Comments of the California Forward Capacity Market Advocates," May 2007, and "Proposal for a Forward California Capacity Market," August 2007.

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PJM Interconnection, LLC, FERC Docket Nos. EL03-236-000 *et al.* Affidavit regarding three-pivotal-supplier market power test and scarcity pricing in PJM's energy markets on behalf of Mirant Energy Trading et al., May 2007.

Midwest Independent Transmission System Operator, FERC Docket No. ER07-550-000. Affidavit regarding resource adequacy issues in ancillary services market design on behalf of Duke Energy Co., March 2007.

PJM Interconnection LLC, FERC Docket No. EL05-148-000 *et al.* Affidavit regarding redesign of the long-run resource adequacy market in PJM on behalf of the Mirant Parties, October 2005; supplemental affidavit on behalf of the Mirant Parties, NRG and Williams Power Co., November 2005; presentation to FERC Technical Conference, February 2006; prefiled comments to FERC Technical Conference Panel 1, May 2006, on behalf of the Mirant Parties, Williams Power Co., and Dayton Power & Light; prefiled comments to FERC Technical Conference Panel 2, May 2006, on behalf of the Mirant Parties; supplemental affidavit on behalf of the Mirant Parties, June 2006; affidavit and reply affidavit supporting settlement agreement, September and October 2006.

Mystic Development, LLC, FERC Docket No. ER06-427-000. Affidavit analyzing future revenues in support of RMR filing, December 2005; supplemental affidavit, September 2006.

In re USGen New England, Inc. Debtor. United States Bankruptcy Court for the District of Maryland, Case No. 03-30465. Expert report on damage resulting from PPA rejection on behalf of USGen New England, March 2006; supplemental report, September 2006.

California Independent System Operator Corporation, FERC Docket No. ER06-615-000. Joint affidavit with Paul Kevin Wellenius regarding FTR allocations under new CAISO market design on behalf of Powerex Corp, June 2006

Fore River Development, LLC, FERC Docket No. ER06-822-000. Affidavit analyzing future revenues in support of RMR filing, December 2005.

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Honeywell International Inc. v. Sunoco, Inc. AAA Case No. 13 181 Y 02588 04. Expert report, deposition and live testimony on contract energy pricing in petrochemicals, May 2005.

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KeySpan Ravenswood LLC v. New York Independent System Operator, Inc., FERC Docket No. EL05-17-000. Affidavit on behalf of Consolidated Edison Company of New York, Inc. regarding retroactive damage claims from a capacity market, November 2004.

Devon Power LLC et al., FERC Docket No. ER03-563-030. Affidavit and rebuttal affidavit regarding design of locational installed capacity markets on behalf of FPL Energy, April and May 2004; answering testimony on behalf of Capacity Suppliers, November 2004; cross-answering testimony, December 2004; supplemental cross-answering testimony, January 2005; deposition and hearing testimony, February to March 2005; affidavit supporting Settlement Agreement, March 2006.

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In the Matter of the Siting of Electric Transmission Facilities Proposed to be Located at the West 49th Street Substation of Consolidated Edison Company of New York, Inc. et al., New York State Public Service Commission Case Nos. 02-M-0132, 01-T-1474, 02-T-0036, 02-T-0061; testimony on behalf of Consolidated Edison Company of New York, Inc., April 2002 (direct) and May 2002 (rebuttal).

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Wisvest-Connecticut, LLC et al., FERC Docket No. EC01-70-000, technical conference presentation on behalf of NRG Energy, Inc. and affiliates, September 2001.

New York Independent System Operator, Inc., FERC Docket No. ER01-2536-000, affidavit on behalf of Consolidated Edison Co. of New York, the City of New York, the New York Energy Buyers Forum, and the Association for Energy Affordability, Inc., July 2001.

Testimony before the Committee on Corporations, Rhode Island House of Representatives regarding electricity restructuring; various dates, 2001.

Consolidated Edison Co. of New York, Inc., FERC Docket Nos. EL01-45-000 and ER01-1385-000, affidavit and rebuttal affidavit (joint with William H. Hieronymus) on behalf of Consolidated Edison Co. of New York, March and April, 2001.

Joint Petition of Consolidated Edison Co. of New York, Inc. and Entergy Nuclear Indian Point 2, LLC, for Authority to Transfer Certain Generating and Related Assets and for Related Relief, NYSPSC Case 01-E-0040, technical conference presentation on behalf of applicants, February 2001.

Professional history

2017-present	*Principal,* Power Market Economics LLC, Portland ME
2016-present	*President & CEO*, GWave LLC, Portland, ME

2013-present	*Senior Consultant,* Charles River Associates, Boston MA
2013–2016	*Executive Vice President,* GWave LLC, Boston MA
2003–2013	*Vice President*, Charles River Associates, Boston, MA
2001–2003	*Principal*, Charles River Associates, Boston, MA
1995–2001	*Managing Consultant*, PA Consulting Group, Cambridge, MA PA purchased PHB Hagler Bailly, formed by the merger of Hagler Bailly and Putnam, Hayes & Bartlett, where Mr. Stoddard had been a Principal.
1993–1995	*Senior Health Economist and Acting Managing Director*, Benefit Research USA, a Quintiles company, Cambridge, MA
1990–1993	*Senior Associate*, Charles River Associates, Boston, MA
1985–1990	*Teaching and Research Fellow*, Department of Economics, Yale University
1983–1985	*Assistant Economist*, Federal Reserve Bank of New York

Education

1990	M.Phil., Economics, Yale University
1986	M.A., Economics, Yale University
1983	B.A. *summa cum laude*, Amherst College; Phi Beta Kappa

Exhibit RBS-2 – Figure 1

Removing FRR Alternative Resource from BRA offer stack does not change the Resource Clearing Price

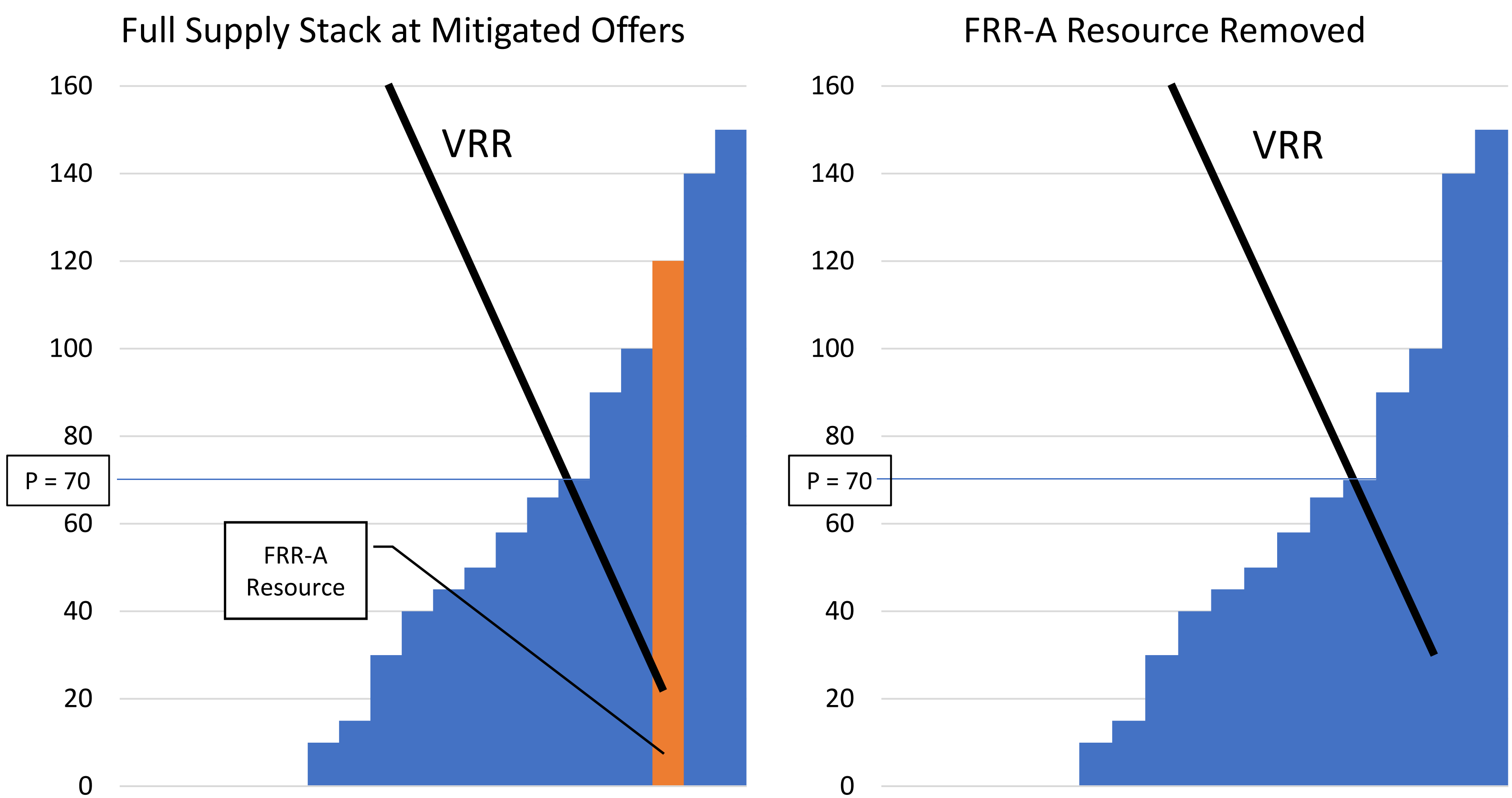

Exhibit RBS-2 – Figure 2

Removing FRR Alternative Resource *and* matched load suppresses the Resource Clearing Price

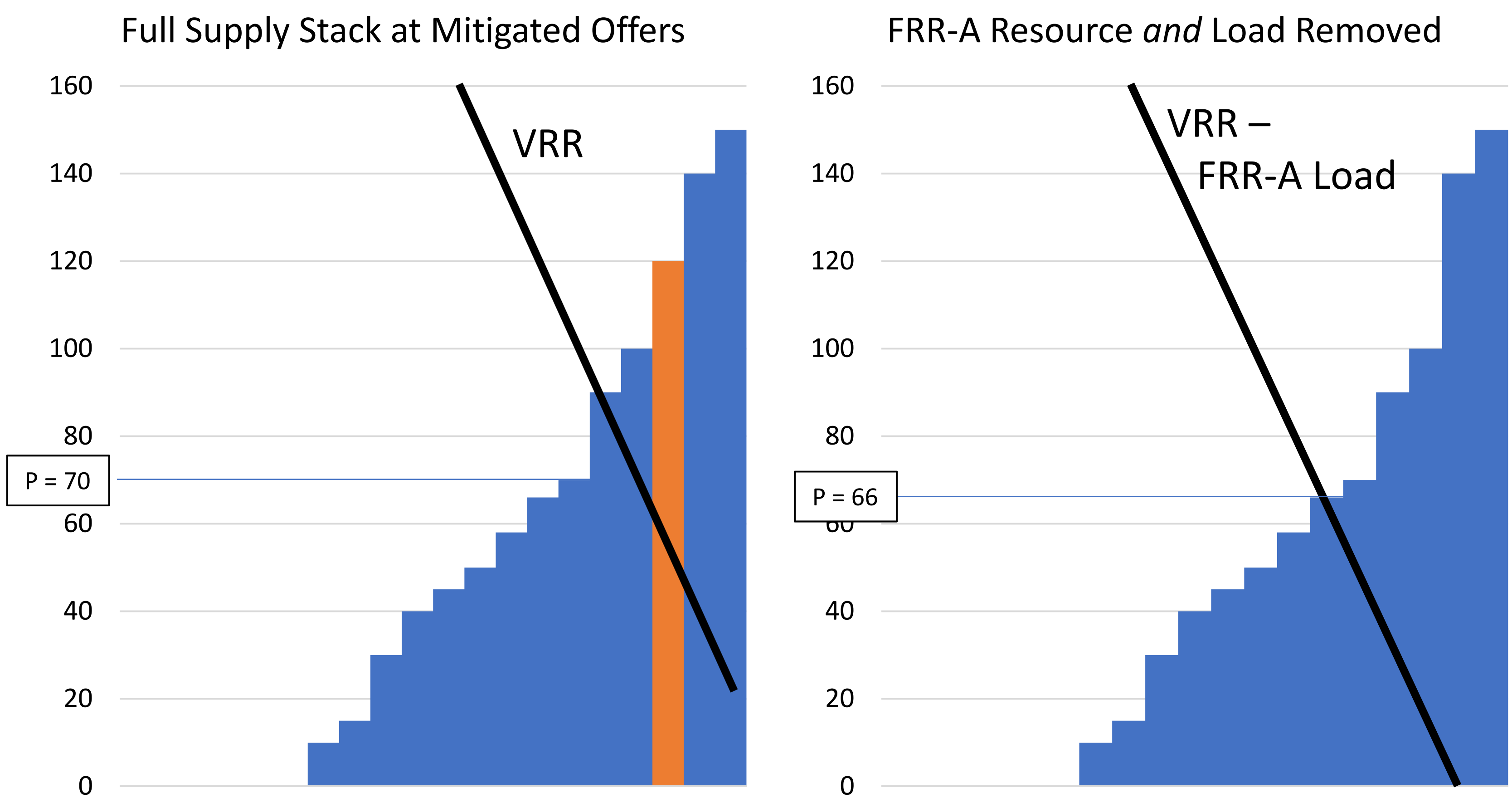

Exhibit RBS-2 – Figure 3

Price suppression of FRR Alternative is similar to eliminating MOPR

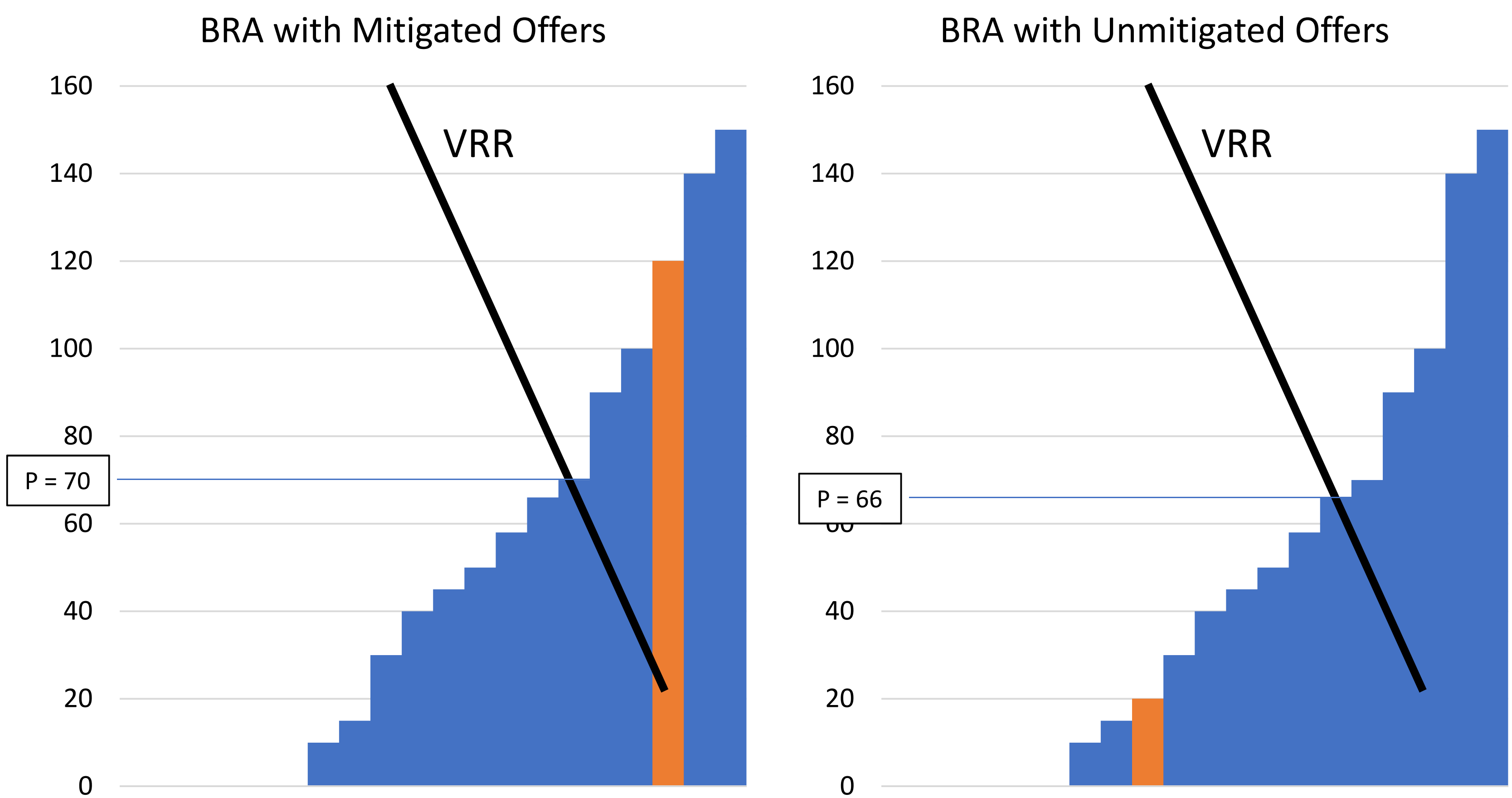

Exhibit RBS-3 – Figure 1

Two-step BRA clearing

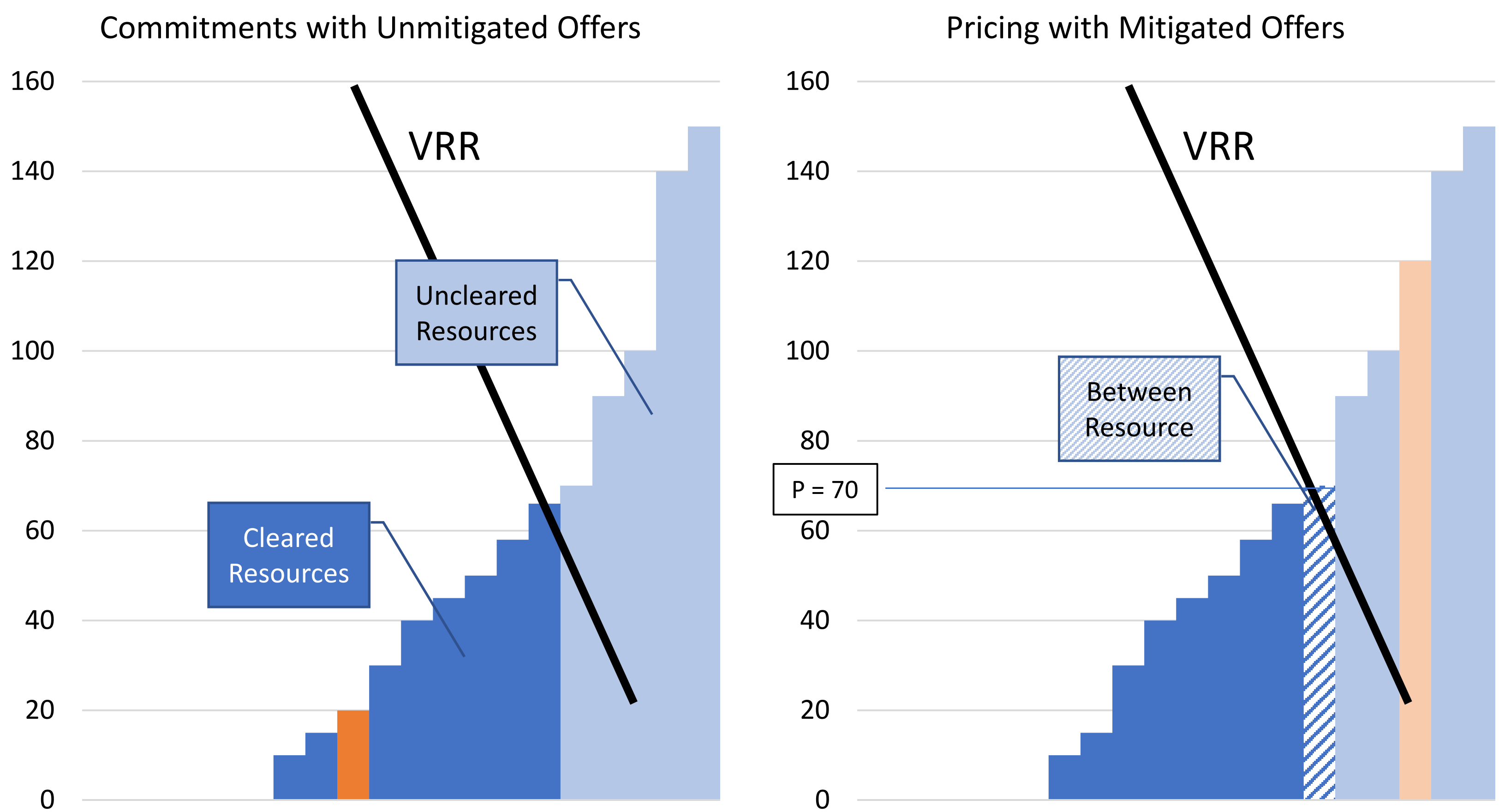

Exhibit RBS-3 – Figure 2

Nested LDAs clear without constraint when subsidized resource is self-scheduled

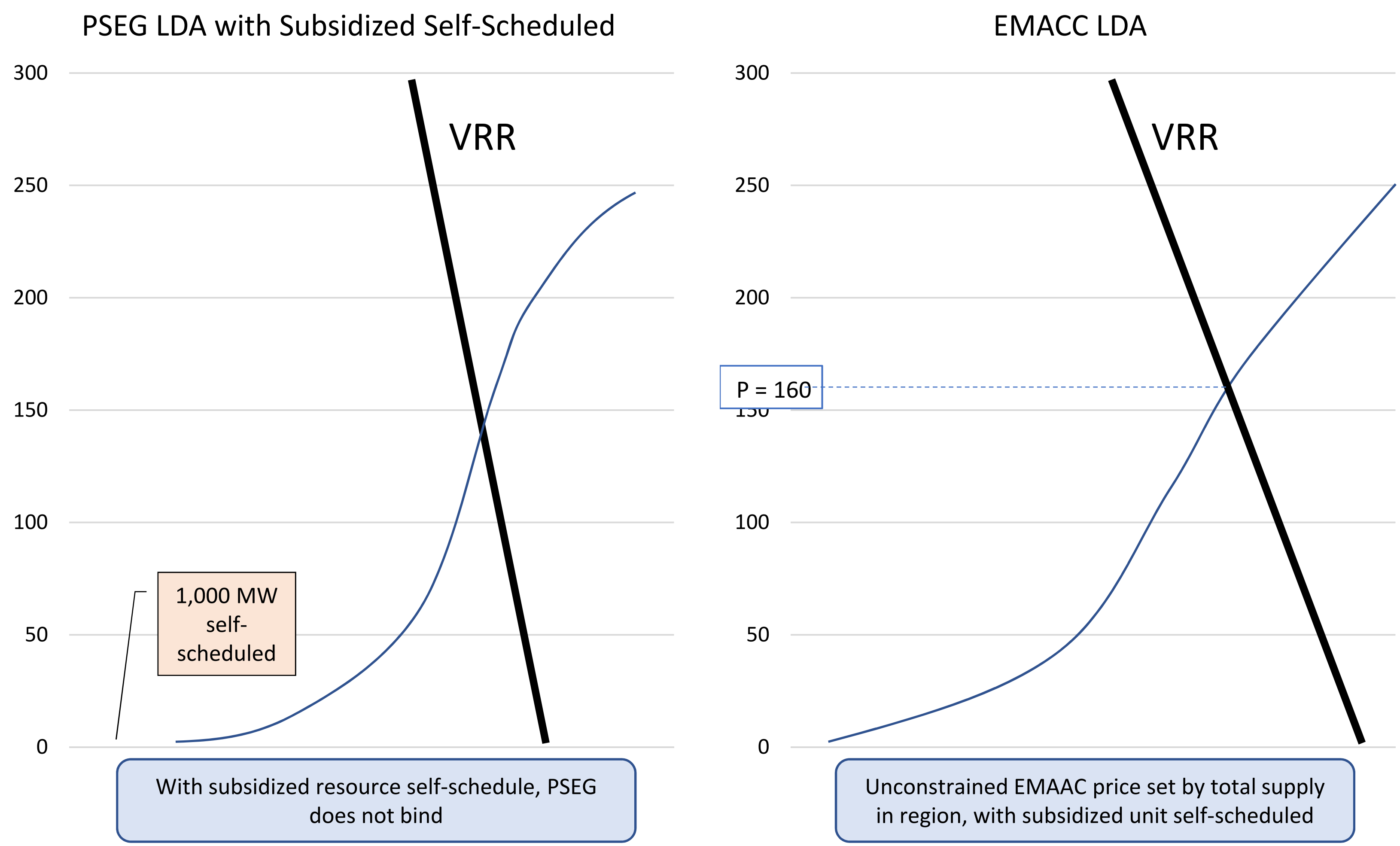

Exhibit RBS-3 – Figure 3

When mitigation reveals price separation, price in constrained-low area can decline