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Date of Hearing: 1/17/2019

Case No. 18-501-EL-FOR, 18-1392-EL-RDR, 18-1393-EL-ATA

PUCO Case Caption: 2018 Long-Term Forecast Report of Ohio Power Company and Related Matters, Application of Ohio Power Company for Approval to Enter Into Renewable Energy Purchase Agreements for Inclusion in the Renewable Generation Rider, and Application of Ohio Power Company for Approval to Amend its Tariffs.

List of exhibits being filed: Volume IV

IGS/IGS Solar LLC-6

OCC 12

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BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO

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In the Matter of the 2018 Long-Term Forecast Report of Ohio Power Company and Related Matters.	Case No. 18-501-EL-FOR
In the Matter of the Application of Ohio Power Company for Approval to Enter Into Renewable Energy Purchase Agreements for Inclusion in the Renewable Generation Rider.	Case No. 18-1392-EL-RDR
In the Matter of the Application of Ohio Power Company for Approval to Amend its Tariffs.	Case No. 18-1393-EL-ATA

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PROCEEDINGS

before Ms. Sarah Parrot and Ms. Greta See, Attorney Examiners, at the Public Utilities Commission of Ohio, 180 East Broad Street, Room 11-A, Columbus, Ohio, called at 9:00 a.m. on Friday, January 18, 2019.

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VOLUME IV

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

INITIAL SUBMISSION OF
PJM INTERCONNECTION, L.L.C.

October 2, 2018

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

INITIAL SUBMISSION OF
PJM INTERCONNECTION, L.L.C.

PJM Interconnection, L.L.C. ("PJM"), pursuant to the Federal Energy Regulatory Commission's ("FERC" or "Commission") June 29, 2018 order[1] and the August 22, 2018 Notice of Extension of Time, hereby provides this initial submission regarding PJM's filing of capacity market rule changes to its Open Access Transmission Tariff ("Tariff") and Reliability Assurance Agreement among Load Serving Entities in the PJM Region ("RAA") to establish the appropriate federal and regional transmission organization

[1] *Calpine Corp. v. PJM Interconnection, L.L.C.*, 163 FERC ¶ 61,236 (2018) ("June 29 Order").

response to address supply-side state subsidies and their impact on the determination of just and reasonable prices in the PJM capacity market.[2]

I. OVERVIEW

In the June 29 Order, the Commission agreed that the integrity and effectiveness of PJM's Reliability Pricing Model "have become untenably threatened by out-of-market payments provided or required by certain states for the purpose of supporting the entry or continued operation of preferred generation resources that may not otherwise be able to succeed in a competitive wholesale capacity market."[3] Moreover, the Commission found that PJM's existing Minimum Offer Price Rule ("MOPR")[4] does not adequately address the price suppressive effect of resources receiving out-of-market payments to ensure a just and reasonable rate.[5] As a result, the Commission found PJM's existing MOPR rules unjust and unreasonable.[6]

The Commission determined that the replacement rate must be put into effect in time for the 2019 Base Residual Auction.[7] In furtherance of that goal, PJM has been working intensively with its stakeholders as well as the Commission's designated non-decisional Staff personnel to inform PJM's proposal contained herein. PJM held multiple multilateral and individual stakeholder meetings and sought written comments to help

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2 PJM also offers one proposed revision to the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C., ("Operating Agreement") where it mirrors a proposed revision to the identical provision in Tariff, Attachment K-Appendix.

3 June 29 Order at P 1.

4 All capitalized terms that are not otherwise defined herein shall have the same meaning as they are defined in the Tariff, Operating Agreement, or the RAA.

5 *Id.* at P 2.

6 *Id.* at 6.

7 *Id.* at PP 172-73.

guide the discussions. Finally, PJM has included in this filing a detailed proposal, affidavits of Dr. Hung-po Chao, PJM Senior Director, Economics (as Attachment C), and Adam Keech, PJM Executive Director, Market Operations (as Attachment B), and pro forma tariff language (as Attachment A) to support its proposal so that the Commission has a complete package for consideration.[8]

A. Legal Standards to Consider in Reviewing PJM's Proposal

Several parties, including recognized economists and market design experts in the industry, argue that the Commission's resource-specific Fixed Resource Requirement ("FRR") option and PJM's proposed implementation of that concept (what PJM is calling a "Resource Carve-Out" or "RCO" described below) must fail because neither can guarantee that clearing prices in the residual market will remain just and reasonable and non-discriminatory.

In contrast, others argue the same price suppression which the Commission found in the first instance to be unjust and unreasonable and justifying application of MOPR, can be excused in the second instance where subsidized resources and load are excluded from the market because the offers and demand curve that form price in the residual market are themselves competitive. This argument seemingly rests on the view that the Commission will have met its statutory responsibility if it simply ensures that market *participation* is competitive, once the market is defined to exclude subsidized offers. This view of the Commission's statutory duties, either ignores the *outcome* of the market or concludes that because *participation* (sell offers) in that market is competitive, then

8 For clarity and convenience, PJM has prepared and attached to this filing (as Attachment D) a consecutive list of pre-auction deadlines for identification of subsidies, determination of applicable MOPR floor prices, and election of the Resource Carve-Out (all as further defined in this filing).

ipso facto, the *outcome* in that market also must be competitive and thus just and reasonable.

In PJM's opinion, neither position is fully correct. We believe the Commission can, if care is taken, lawfully afford states that subsidize preferred generation the option to have these resources recognized as capacity outside PJM's capacity market. However, PJM believes *both* participation (offers) and outcomes (prices) in the residual capacity market regulated by the Commission must remain competitive in order to meet the Commission's statutory duty. As the Commission fully appreciates, its central role is as a price regulator. Thus, its duty to uphold competitive prices is not met merely by sanitizing the residual market from subsidized offers – it must additionally examine the price outcome in that residual market and be satisfied such prices are just and reasonable. The Commission can do so here by ensuring the design of the June 29 Order's suggested bifurcated approach to procuring capacity (i.e., part auction-based and part carved-out) is competitive. Looking holistically at capacity procurement in PJM – both carved out and market cleared resources – does the structure, as a whole, work to meet its design objectives and is it just and reasonable? In order to answer these questions in the affirmative, the Commission must do more in sanctioning an alternative to MOPR than accept a rule that merely removes the subsidized "offending" participants (offers and associated load) from the market.

The first step to reconcile the challenge raised by a bifurcated market is to accept that a trade-off is inescapable. An unfettered path allowing those states relying on PJM's resource adequacy markets to nonetheless advance preferred resource types will render PJM's residual and overall market unlawful under the Federal Power Act ("FPA"). But, by the same token, seeking perfect market outcomes, such as would be the case by applying just the MOPR, leaves these states no practical option to pursue generation-related public policy goals through subsidy. Making room, outside the auction, to accept subsidized generation as a PJM "Capacity Resource" ineluctably will degrade auction prices.[9] Unless the Commission is prepared to accept a mechanism to adjust prices to their "correct" level, this trade-off must be understood as an unavoidable consequence that comes once uneconomic resources are relieved from having to participate in the market.

If this trade-off is to be accepted, the second step is then to determine what terms and conditions must apply to ensure degradation away from a theoretically correct residual capacity price is limited and, in any case, does not proceed to a point where price outcomes can no longer be regarded as just and reasonable or able to serve the important design purposes central to using a market mechanism to meet resource adequacy needs. The principal legal question here is: *what terms and conditions must apply to a Resource Carve-Out option in order to assure, not merely that participation (market seller offers in*

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9 As many in this docket will no doubt explain at length, simply removing subsidized resources and an equivalent amount of load from a capacity auction would likely result in a suppressed clearing price similar to that which would result in retaining the subsidized resource and load. *See* Chao Aff. ¶ 10. As the Commission found in its June 29 Order, the resulting price in this circumstance is not a just and reasonable price.

Thus, a "carve out" can work only if prices in the residual market continue to meet just and reasonable standards. To ensure this outcome, the Commission must accept either (i) terms and conditions that acknowledge, but limit, price suppression, or (ii) rules that explicitly correct the price suppressive impact. As explained further below, PJM proposes here both options.

the residual market) is competitive, but also that the outcome of that market remains just and reasonable.[10]

The just and reasonable standard is not one of perfection. Even under traditional cost of service ratemaking it was accepted that, "(t)he factors involved in ratemaking are so many and so variable that it is impossible to fix rates that will be mathematically correct or exactly applicable to all the new conditions that may arise even in the immediate future."[11] In the context of organized electricity markets, such as PJM's, the equitable aspect of the just and reasonable standard has been expressed in terms of "workably competitive" outcomes.[12]

Application of this standard to the question giving rise to this docket argues the Commission is on solid grounds in striking a lawful balance to this trade-off by applying

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10 PJM is focusing for the moment on the Commission's duty to ensure prices in the "residual" capacity market remain just and reasonable. It can be noted, and PJM will offer further explanation *infra*, that any separate transaction to charge wholesale load a rate to compensate the carved out resource for the capacity it provides, is additionally a FERC jurisdictional rate. This transaction too must conform to FPA standards.

11 *Hammond Lumber Co. v. Pub. Serv. Comm'n*, 189 P. 639, 643 (Or. 1920). *See also Morgan Stanley Capital Grp. Inc. v. Pub. Util. Dist. No. 1 of Snohomish Cty.*, 554 U.S. 527, 532 (2008) ("[W]e afford great deference to the Commission in its rate decisions" because "'just and reasonable' is obviously incapable of precise judicial definition."); *Duquesne Light Co. v. Barasch*, 488 U.S. 299, 314 (1989) ("The economic judgments required in rate proceedings are often hopelessly complex and do not admit of a single correct result.").

12 *Consol. Edison Co. of N.Y., Inc. v. FERC*, 347 F.3d 964 (D.C. Cir. 2003) (market design flaw would result in unjust and unreasonable market outcomes that would not be produced in a workably competitive market); *see, e.g.*, Devin Hartman, *R Street Policy Study No. 67 2016 Wholesale Electricity Markets in the Technological Age*, R Street, 5 (Aug. 2016), https://www.rstreet.org/wp-content/uploads/2016/08/67.pdf ("'Just and reasonable' rates merely must be workably competitive, not perfectly competitive. Generally, workably competitive markets have firms with limited market power and exhibit few barriers to entry or exit.").

rules of reasonableness, limitation, and materiality. Accordingly, PJM has approached formulating the instant proposal by admitting some degree of intervention has been and can continue to be tolerated without resulting in capacity market outcomes that are unjust and unreasonable.[13] But there comes a "tipping point" where the trade-off involved has tilted so far to one side and the degradation to residual market clearing prices has advanced to such a point that outcomes in this market cease to be just and reasonable.[14]

To that end, PJM proposes both an expanded MOPR and Resource Carve-Out construct. The Resource Carve-Out is designed to realize the concept suggested in the June 29 Order to offer an alternative to MOPR that would permit subsidized resources to obtain a capacity commitment, but do so without having to clear the PJM capacity

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13 Prices in organized electricity markets always have been subject to the impact of some level of subsidy and other out-of-market support since their inception, without resulting in uncompetitive outcomes. Further, even under the MOPR proposed here at the Commission's direction - one whose reach broadly covers new and existing resources of all fuel types - there are still reasonable exclusions based on materiality of both the resource and the subsidy. These kinds of departures from theoretical perfection have been upheld by the Courts. *See FERC v. Elec. Power Supply Ass'n*, 136 S. Ct. 760, 776 (2016) (noting that FERC regulated markets were not expected to be "hermetically sealed" from state authority). Speaking directly to the question at hand, the D.C. Circuit, just several months ago, found "the Commission reasonably balanced the potential for limited price suppression against competing interests in concluding that the renewable exemption to the minimum offer price rule is consistent with the purpose of the forward capacity market." *NextEra Energy Res., LLC v. FERC*, 898 F.3d 14 (D.C. Cir. 2018).

14 Even at this point, options still remain available to the states. In addition to application of MOPR, states and their regulated utilities that assume comprehensive responsibility for resource adequacy, either through PJM's existing zonal FRR rule or by re-regulating bundled utility sales, are free to promote any individual resource without regard to the effect on PJM's capacity market.

market.[15] The expanded MOPR, coupled with the Resource Carve-Out as proposed here, offers the Commission a defensible FPA-compliant path to accept and limit the trade-off that comes from recognizing subsidized, and hence uneconomic, resources as PJM capacity.

But additionally, for the Commission's further consideration under FPA section 206,[16] PJM describes an approach that would combine the Resource Carve-Out with an explicit mechanism to restore prices in the residual capacity market to the theoretically correct competitive level. This approach is described as the "Extended Resource Carve-Out" or "Extended RCO."

B. Summarizing the Basic Elements of the PJM Proposal

MOPR: *The proposed expanded MOPR applies across all fuel and technology* types and to existing as well as new resources. The path to determine whether a resource is subject to MOPR includes situational exceptions and rules defining when subsidies are "actionable." PJM believes these limited exceptions and rules (which largely rest on materiality tests) are narrow and fall comfortably within the legal standards noted above, allowing reasonable departures from a theoretically perfect market, and reflect reasonable

[15] The Resource Carve-Out is designed to offer states a means to support particular generation assets by removing them from the capacity market where, otherwise, offers from these resources would be subject to MOPR. PJM has decided to refer to this rule set as the "Resource Carve-Out" as opposed to a unit-specific FRR because, as will become evident herein, it differs sufficiently from PJM's existing zonal FRR to warrant a distinct name in order to avoid confusion.

[16] 16 U.S.C. § 824e (2016).

judgment calls for which the Commission is entitled to a high degree of deference from a reviewing court.[17]

RCO: Also for reasons stated above, PJM believes the Resource Carve-Out or RCO must impose certain rules and limitations on resources seeking a carve-out in order that deviations in residual market price outcomes from a theoretically correct price remain tolerable and within the bounds of a just and reasonable rate. These rules and limitations include:

- Offering the carve-out option only to those resources subject to MOPR and only those resources receiving a state (but not to resources receiving an actionable federal) subsidy);
- Rules defining the amount of load associated with a carved out resource;
- Rules regarding the allocation to load of the credit associated with the carved out resource and the role of FERC in accepting any alternate methodology desired by a state;

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17 The Supreme Court has stated, for example, that the Commission "must be free, within the limitations imposed by pertinent constitutional and statutory commands, to devise methods of regulation capable of equitably reconciling diverse and conflicting interests." *Permian Basin Area Rate Cases*, 390 U.S 747, 767 (1968) (construing comparable rate-setting provisions of the Natural Gas Act). More recently, in reviewing the Commission's application of "technical understanding and policy judgment," in deciding between competing approaches to compensating demand response in organized electricity markets, the Court stated:

> [I]n upholding (the Commission's chosen approach), we do not discount the cogency of EPSA's arguments in favor of LMP-G. Nor do we say that in opting for LMP instead, FERC made the better call. It is not our job to render that judgment, on which reasonable minds can differ. Our important but limited role is to ensure that the Commission engaged in reasoned decisionmaking—that it weighed competing views, selected a compensation formula with adequate support in the record, and intelligibly explained the reasons for making that choice. FERC satisfied that standard.

FERC v. Elec. Power Supply Ass'n, 136 S. Ct. 760, 784 (2016).

- Applying the carve-out for the life of the subsidy and applying MOPR on previously carved out resources seeking to re-enter the capacity market; and
- Acknowledgment that if the amount of capacity carving out becomes so large going forward, PJM and the Commission will need to evaluate whether the residual market is sufficiently robust to perform effectively and consistent with the FPA.

Extended RCO: Finally, mindful that the terms and conditions associated with RCO (the most important having been summarized in the bullets immediately above) do not entirely insulate residual market clearing prices from the trade-off that comes from awarding uneconomic resources a capacity commitment, and understanding the FPA section 206 nature of this proceeding, PJM also offers for consideration the Extended RCO. As the name implies, this proposal takes the RCO alternative and adds an explicit mechanism, not unlike PJM's Capacity Repricing, to restore the residual market clearing price closer to the economically correct outcome. But unlike Capacity Repricing, Extended RCO includes features designed to address the Commission's concerns expressed in the June 29 Order that proved fatal to that earlier proposal.

By including a price adjustment mechanism, Extended RCO continues to treat subsidized resources electing an alternative to MOPR as "carved out" resources that do not participate, and thus are neither offered in, nor compensated by, the PJM capacity market. And by completely isolating the subsidized resource from PJM's capacity market, and thus not paying the resource a capacity payment out of the PJM market, Extended RCO addresses a concern that led the Commission to reject Capacity Repricing in its June 29 Order—namely, a concern that paying subsidized resources the reconstituted capacity price amounted to an unfair windfall.

Extended RCO also includes price formation rules that work to ensure the market clearing price counters the price suppression that otherwise would result from a "stand-alone" RCO. This mechanic, however, is simpler than what PJM proposed in Capacity Repricing because it forsakes use of proxy offers (MOPR-priced offers from subsidized resources already awarded a capacity commitment) and instead establishes clearing prices based on actual offers, but clears these offers against PJM's total load requirements, including the load associated with the carved out resource. Retaining the full complement of load in the clearing and price formation phase of the auction will work to redress to a large degree the price suppression that comes naturally as a trade-off in offering the RCO alternative. But this same feature will also result, as it did in Capacity Repricing, in some resources which, in reference to the clearing price, are economic and should thus receive a commitment, but which will nonetheless be crowded out - displaced by the carved out resources previously accepted as capacity.

The crowding-out problem was an additional basis upon which PJM's Capacity Repricing was rejected in the June 29 Order.[18] The situation still occurs under Extended RCO; however PJM proposes here rules to mitigate its problematic effects by compensating such resources through an infra-marginal rent, calculated as the difference between a crowded out resource's offer price and the Extended RCO clearing price.

Extended RCO would more explicitly and directly correct the price suppressive effect on the residual market, and protect it from the potential for monopsony power, than the stand-alone RCO. However, as noted above, the Commission is empowered to recognize and accept some trade-off and departure from the pure economics textbook outcome. For this reason, with the terms and conditions included, PJM advances RCO as

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18 June 29 Order at P 154.

a just and reasonable approach which the Commission can accept to offer states a further alternative to MOPR, full re-regulation or PJM's existing FRR rules.

C. Summarizing when the PJM Proposal Would Apply

PJM's proposed MOPR/RCO would apply to new and existing resources of all fuel and technology types that seek recognition as a PJM Capacity Resource when:

- such resource is a material resource that,
- receives a Material Subsidy.

Simply stated, all material resources receiving materials subsidies are actionable under the proposal. A material resource is any resource, *except*:

- a resource having an unforced capacity value of less than 20 MWs; or
- a resource existing not primarily to produce electricity, but one whose *electricity production is a function ancillary to a more primary function*, such as most waste to energy or combined heat and power facilities.

A Material Subsidy is any subsidy, *except*:

- generic economic development subsidies not specific to the electricity sector, production of electricity or the investment in electric generation; or
- a resource-specific subsidy (state or federal) that is 1% or less of the expected PJM revenues the resources expects to receive; or
- renewable energy credit programs (RECs), where the market seller sells the REC to a purchaser that is not required by a state program to purchase the REC, and that purchaser does not receive any state financial inducement or credit for the purchase of the REC; or
- federal subsidy programs enacted into law prior to March 21, 2016.

Additionally, a resource owned by a vertically integrated utility subject to traditional bundled rate regulation or a resource owned by a public power entity, in both cases developed to meet the self-supply needs of the integrated utility or public power system, will not be considered material resources receiving a Material Subsidy, provided the resource owners meet a stated net long/net short test where applicable. Finally, resources receiving certain federal subsidies pursuant to programs enacted *after* March 21, 2016 will, with some limitation described below, be subject to PJM's proposal, except that these resources will not be able to avail themselves of RCO as an alternative to MOPR.

D. Overview Conclusion

PJM's proposed MOPR/RCO includes terms and conditions necessary to ensure outcomes can be expected to be workably competitive in the residual capacity market. Broadly speaking, the design of these terms and conditions is informed by:

(i) an important underlying objective stated in the June 29 Order—namely that states which choose to support generation for policy reasons not recognized in the Commission-regulated wholesale markets assume all costs associated with this decision in a transparent fashion; and

(ii) an understanding the Commission, in setting just and reasonable rates, can exercise informed judgment to adopt reasonable balances and draw distinctions based on materiality to accommodate varying industry objectives in an environment of cooperative federalism.

As noted, RCO *with* appropriate terms and conditions included can work to provide workably competitive auction clearing prices consistent with FPA requirements. RCO, however, necessitates accepting some degree of price suppression—what PJM terms as a "trade-off." We regard the expected potential for price degradation in the residual market under the RCO as workable and acceptable under FPA standards.[19]

But in addition, given the Section 206 nature of this proceeding, PJM proposes here for the Commission's additional consideration an Extended RCO that includes a mechanism designed to address directly the price suppressive impact to the residual capacity market; a methodology to compensate economic resources crowded out by RCO; and recoupment of that compensation from sellers that elect the RCO for their uneconomic resources and thereby crowd out the affected economic resources.

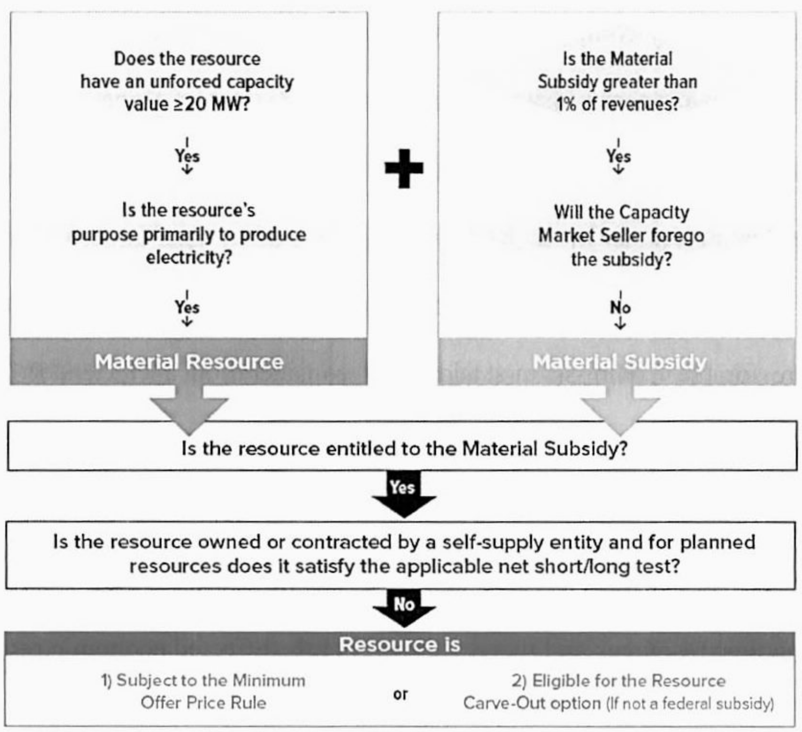
[19] *See* note 13, *supra*, for a discussion of judicial review of prices in organized electricity markets.

II. DETAILS OF PJM's PROPOSAL

A. Defining a Capacity Resource with Actionable Subsidy

To ensure that only those resources that receive a subsidy that warrants action based on design or market impact, PJM proposes to use materiality criteria to identify resources subject to the MOPR (and eligible for the Resource Carve-Out). As explained in section II.D.2 below, Capacity Market Sellers will need to let PJM know the status of each of its resources (i.e., whether it has an Actionable Subsidy or not) prior to the first Base Residual Auction ("BRA") for which it seeks to offer or elect to carve out.

Simply, as described herein, a material resource with a Material Subsidy will be considered a Capacity Resource with Actionable Subsidy. Furthermore, a resource is not a Capacity Resource with Actionable Subsidy if it is the resource of a self-supply entity and meets the net short and net long criteria, described in section II.A.4 below.



1. Material Resources

PJM proposes that Demand Resources and Generation Capacity Resources—existing and planned, internal and external—that meet certain materiality criteria are considered material resources.[20] This is consistent with the Commission's call for "limited exceptions" as set forth in the July 29 Order.[21]

Specifically, a material resource is any resource, *except*:

- a resource having an unforced capacity value of less than 20 MWs; or
- a resource existing not primarily to produce electricity, but one whose electricity production is a function ancillary to a more primary function, such as most waste to energy or combined heat and power facilities.

This is consistent with the Commission's call for limited exceptions as set forth in the July 29 Order.[22]

a. A Capacity Resource Must Be 20 MWs or Greater to Be Deemed a Material Resource

The 20 MW threshold carries forward the same materiality threshold to MOPR application that the Commission previously accepted as consistent with established FPA standards.[23] Some commenters will claim this exemption is too broad, allowing too many resources to avoid the MOPR rules. PJM does not agree. Excluding resources that

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20 *See* pro forma PJM Tariff, Attachment DD § 5.14(h)(ii)(a). PJM is excluding Energy Efficiency Resources from being able to qualify as a Capacity Resource with Actionable Subsidy because such resources are generally the result of a focus on reduced consumption and energy conservation, which are on the demand side of the equation, and do not raise price suppression concerns.

21 June 29 Order at P 158.

22 *See id.*

23 *See PJM Interconnection, L.L.C.*, 143 FERC ¶ 61,090, at P 170 (2013), *reh'g denied*, 153 FERC ¶ 61,066 (2015), *vacated & remanded sub nom. NRG Power Mktg., LLC v. FERC*, 862 F.3d 108 (D.C. Cir. 2017), *reh'g denied*, 2017 U.S. App LEXIS 18218 (D.C. Cir. Sept. 20, 2017) (per curiam).

are less than 20 MW in size will have little real consequence to the objectives of the rules.

The Commission and the PJM Tariff have long recognized different rules based on a 20 MW threshold. For instance, while finding that "no single per-MW demarcation is perfect," the Commission found a 20 MW materiality threshold to be "reasonable and administratively workable" for implementing the Public Utility Regulatory Policy Act of 1978 ("PURPA").[24] Thus, the Commission determined that Qualifying Facilities of 20 MW or less should be exempt from regulation under sections 205[25] and 206 of the FPA.[26] Similarly, the Commission was "[p]ersuaded that different procedures and agreements [than those for larger resources] were indeed needed" to govern interconnection of

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24 *New PURPA Section 210(m) Regulations Applicable to Small Power Production and Cogeneration Facilities*, Order No. 688, 2006-2007 FERC Stats. & Regs., Regs. Preambles ¶ 31,233, at PP 72, 76 (2006) (adopting a rebuttable presumption that "small" Qualifying Facilities may not have nondiscriminatory access to markets because of their size and defining "small" as less than 20 MW), *order on reh'g*, Order No. 688-A, 2006-2007 FERC Stats & Regs., Regs Preambles ¶ 31,250 (2007); *see also Revised Regulations Governing Small Power Production and Cogeneration Facilities*, Order No. 671, 2006-2007 FERC Stats. & Regs., Regs. Preambles ¶ 31,203, at P 98 (adopting exemption under PURPA for Qualifying Facilities 20 MW or smaller from sections 205 and 206 of the FPA), *order on reh'g*, Order No. 671-A, 2006-2007 FERC Stats.& Regs., Regs Preambles ¶ 31,219 (2006).

25 16 U.S.C. § 824d.

26 *See* 18 C.F.R. § 292.601(c).

resources smaller than 20 MW.[27] As a result, PJM uses 20 MW as a materiality standard in its interconnection procedures.[28]

As Mr. Keech shows in his affidavit, a 20 MW materiality threshold will not significantly impact the participation of renewables in the capacity market. First, the nameplate capacity of the resource is not equivalent to the amount of Unforced Capacity that can be offered into the capacity market. Unforced Capacity "represents the megawatt quantity of energy that the resource can reliably contribute during peak hours,"[29] and the intermittent nature of wind and solar resources results in their nameplate capacity being discounted to determine Unforced Capacity. For example, in 2017, the default capacity factors for wind varied from 14.7% to 17.6%, and for solar from 38.0% to 60.0%.[30] Thus, a wind resource may need to have a nameplate capacity of 137 MW or greater to have an Unforced Capacity of 20 MW (137 * 0.147 = 20.139). Second, in the

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27 *Standardization of Small Generator Interconnection Agreements and Procedures*, Order No. 2006, 2001–2005 FERC Stats. & Regs., Regs. Preambles ¶ 31,180, at P 17, *order on reh'g*, Order No. 2006-A, 2001–2005 FERC Stats. & Regs., Regs. Preambles ¶ 31,196 (2005), *order on clarification*, Order No. 2006-B, 2006–2007 FERC Stats. & Regs., Regs. Preambles ¶ 31,221 (2006).

28 *See, e.g.*, PJM Tariff, Part IV, subpart G (providing streamlined interconnection processes for Generation Interconnection Requests for new generation resources of 20 MW or less or "small resource" capacity or energy additions of 20 MW or less); Attachment O, Appendix 2, section 4.7 (utilizing 20 MW demarcation in determining power factor measurement).

29 Keech Aff. ¶ 34 n.9.

30 *See id.*; *see also Class Average Capacity Factors*, PJM Interconnection, L.L.C. (June 1, 2017), https://www.pjm.com/-/media/planning/res-adeq/class-average-wind-capacity-factors.ashx?la=en. Sellers may request resource-specific capacity factors to determine the Unforced Capacity of their solar or wind resource. *See* System Planning Department, *PJM Manual 21*, PJM Interconnection, L.L.C., Appendix B (Jan. 1, 2017) https://www.pjm.com/-/media/documents/manuals/m21.ashx (detailing how to calculate resource-specific capacity factors for wind and solar resources).

PJM Region (plus one pseudo-tie), there are only 629 MW of Unforced Capacity from existing solar and wind resources that exceed the 20 MW size threshold. Even if those 629 MW met all the other criteria for being a material resource, those resources would likely not be impacted by being subject to the MOPR given the low going-forward market costs and expected market revenues for wind and solar resources.[31] Finally, as detailed in Mr. Keech's affidavit, PJM estimates that only 624 MW of planned wind and solar resources currently in the Interconnection Queue with an Unforced Capacity of greater than 20 MW are commercially viable and potentially subject to the MOPR.[32] The proposed 20 MW materiality threshold therefore likely has a *de minimis* impact on renewable participation in the capacity market.

Accordingly, such a materiality threshold is reasonable, as excluding resources that are less than 20 MW will have little real consequence to the objectives of the rules. The proposed 20 MW threshold for material resources is consistent with the objective of a reasonable and administratively workable market, by providing a clear demarcation that excludes resources that are too small, individually or collectively, to meaningfully impact price outcomes from the expanded MOPR. In other words, the threshold falls comfortably within the Commission's equitable discretion to exempt some resources as immaterial in light of the design and operation of the market, on one hand, and precedent, history and policy on the other.

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31 Keech Aff. ¶ 36.

32 Keech Aff. ¶¶ 39-40.

b. A Resource Whose Primary Function Is Not Energy Production Is Not considered a Material Resource

PJM proposes to exclude Capacity Resources for which energy production is a byproduct of a resource owner's primary economic interest in the facility. Such resources include those fueled entirely by, for example, landfill gas, wood waste, municipal solid waste, black liquor, coal mine gas, or distillate fuel oil. Energy production is a byproduct of these resources' primary economic purpose (e.g., managing waste). As such, the economics of energy production and energy market participation for these resources is much more complicated than for a typical Generation Capacity Resource. Thus, obtaining capacity market revenues is not necessarily critical to such resources, and they likely do not raise the price suppression concerns that these market rules address. More importantly, the forces motivating the investment in these resources in the first instance, or their retention, are likely to be overwhelmingly associated with the primary purpose of the resource, e.g., the management of municipal waste and not participation in PJM's markets.

2. Material Subsidy – General

What is a Material Subsidy? The June 29 Order did not specifically reject PJM's proposed definition of Material Subsidy.[33] As PJM explained in its April 9 Filing, the definition of Material Subsidy was derived from what was the competitive entry exemption of the MOPR rule prior to the *NRG* remand.[34] PJM proposes defining a Material Subsidy as follows:

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33 June 29 Order at PP 100-106 (rejecting MOPR-Ex proposal but remaining silent on proposed definition of Material Subsidies).

34 Capacity Repricing or in the Alternative MOPR-Ex Proposal of PJM Interconnection, L.L.C., Docket No. ER18-1314-000, at 70 (Apr. 9, 2018) ("April

> "Material Subsidy" shall mean: (1) material payments, concessions, rebates, or subsidies as a result of any state governmental action connected to the procurement of electricity or other attribute from an existing Capacity Resource, or the construction, development, or operation, (including but not limited to support which has the effect of allowing the unit to clear in any RPM Auction) of a Capacity Resource, or (2) other material support or payments obtained in any state-sponsored or state-mandated processes, connected to the procurement of electricity or other attribute from an existing Capacity Resource, or the construction, development, or operation, (including but not limited to support which has the effect of allowing the unit to clear in any RPM Auction), of the Capacity Resource, or (3) material payments, concessions, rebates, or subsidies authorized pursuant to federal legislation or a federal subsidy program enacted after March 21, 2016 connected to the construction, development, or operation, (including but not limited to support which has the effect of allowing the unit to clear in any RPM Auction) of the Capacity Resource unless such federal legislation specifically exempts the application of MOPR to the program being authorized pursuant to federal legislation, or (4) other material support or payments obtained in any federally-sponsored or federally-mandated processes enacted after March 21, 2016, connected to the construction, development, or operation, (including but not limited to support which has the effect of allowing the unit to clear in any RPM Auction), of the Capacity Resource, unless such federal legislation specifically exempts the application of MOPR to the program being authorized pursuant to federal legislation, provided that any subsidy under (1) through (4) is 1% or more of the resource's actual or anticipated total revenues from PJM's energy, capacity, and ancillary services markets.[35]

To ensure only those subsidies that are material to the resource's capacity market offers are considered, PJM also proposes to exclude certain types of local, state, and federal subsidies from consideration, as follows:

> A Material Subsidy shall not include (5) payments (including payments in lieu of taxes), concessions, rebates, subsidies, or incentives designed to incent, or participation in a program, contract or other arrangement that utilizes criteria designed to incent or promote, general industrial development in an area; (6) payments, concessions, rebates, subsidies or incentives from a county or other local governmental authority using

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9 Filing") (as amended April 16, 2018); *NRG*, 862 F.3d 108. *See also PJM Interconnection, L.L.C.*, 161 FERC ¶ 61,252 (2017).

35 *See* pro forma Tariff, Article I, Definitions.

eligibility or selection criteria designed to incent, siting facilities in that county or locality rather than another county or locality; or (7) A renewable energy credit (including for onshore and offshore wind, as well as solar, collectively, RECs) will not be considered to be a Material Subsidy, if the Capacity Market Seller sells the REC to a purchaser that is not required by a state program to purchase the REC, and that purchaser does not receive any state financial inducement or credit for the purchase of the REC.[36]

By defining both which subsidies to include and which to exclude, the rules provide Capacity Market Sellers with guidance to determine, through the process described below, whether their resources receive a Material Subsidy and guidance to further determine if their resources are Capacity Resources with Actionable Subsidy and subject to the MOPR or eligible for RCO.

a. 1% Revenue Test

Because the purpose of these market reforms is to address the price suppressive effects of material subsidies on BRA clearing prices, PJM is proposing to exclude from the definition of Material Subsidy financial support that, practically speaking, does not raise price suppression concerns. To eliminate such actions from consideration, PJM proposes to exclude from the definition of Capacity Resource with Actionable Subsidy those resources where subsidy (be it a state or federal subsidy (subject to the conditions regarding federal subsidies described below)) accounts for less than 1% of the resource's actual or anticipated PJM-market revenues.[37] Excluding Capacity Resources that receive a non-material level of Actionable Subsidies, i.e., less than 1% of the resource's actual or anticipated total revenues from PJM's energy, capacity, and ancillary services markets,[38]

36 *See id.*

37 *See id.*

38 *See id.*

recognizes that de minimis support a unit might receive, such as the benefit a local municipality might confer on a resource by plowing the snow from a private road accessing the plant site, is not captured by federal rules intended to address a real and specific problem of a Material Subsidy.

Also, PJM proposes excluding wind and solar renewable energy credits ("RECs") to the extent the seller sells the REC to a purchaser that is not required by a state program to purchase the REC, and that purchaser does not receive any state financial inducement or credit for the purchase of the REC. This exclusion is reasonable as it ensures only those subsidies provided through a state program, rather than through a voluntary bilateral arrangement (such as with an end-user seeking to retire the REC to fulfill its voluntary corporate green energy goals) are considered a Material Subsidy under the rules. Indeed, PJM views this as more in the nature of a clarification. RECs were developed, and still are largely used, as a means for load-serving entities to demonstrate compliance with mandatory state renewable portfolio standard programs. While the market value of RECs may fluctuate, their purchase by Load Serving Entities ("LSEs") (as an alternative to the LSE building its own renewable generator) is mandated by the state, and is designed by state RPS programs as a means to flow revenues to the state-desired renewable resources so as to help meet statutory RPS requirements for renewable generation share. In recent years, however, a parallel market has arisen for voluntary REC purchases, unrelated to RPS mandates, by non-LSEs. For the most part, this demand is from private corporations pursuing adopted missions to reduce the corporation's environmental impacts. Because these purchases do not arise from a state mandate, they are reasonably distinguished from the large bulk of REC purchases made to show compliance with state RPS mandates, and thus are reasonably not considered state subsidies.[39]

b. Certain Revenues Not Considered Subsidies

PJM recognizes resources may receive a subsidy that is unrelated to production of electricity but rather that are aimed at economic development through development grants, tax credits and the like. Thus, to ensure that only those subsidies that are material to the resource's capacity market impact are considered, PJM is also proposing to exclude certain types of generic subsidies that are unrelated to the supply-side participation from consideration:

- payments (including payments in lieu of taxes), concessions, rebates, subsidies, or incentives designed to incent, or participation in a program, contract or other arrangement that utilizes criteria designed to incent or promote, general industrial development in an area; or

- payments, concessions, rebates, subsidies or incentives designed to incent, or participation in a program, contract or other arrangements from a county or other local governmental authority using eligibility or selection criteria designed to incent, siting facilities in that county or locality rather than another county or locality.

39 PJM's pro forma Tariff language, however, attaches two reasonable protections to this distinction. First, since most ultimate REC purchases are for RPS compliance, generator REC sales to an intermediary are presumed to be for ultimate purchase to meet RPS mandates, and thus would be considered a subsidy. Outside of end-user purchases of RECs in order to retire them to meet corporate green energy goals, other REC transactions are difficult to trace and could be used to serve as subsidy vehicles from states to generators in different forms. Second, if the subsidy to the generator takes some other form than a traditional bilateral REC transaction between private entities, the proposed tariff language does not shield state financial inducements or credits from being treated as a subsidy for purposes of application of the MOPR. PJM has kept this exception narrow so as to avoid gaming opportunities. As a practical matter, since RECS are only issued to in-service units producing renewable energy, and because the going-forward costs of existing renewables are quite low, application of MOPR to RECs should not materially impact the renewable unit's ability to clear in the capacity auction. For all these reasons, further widening of this "corporate procurement" exception would not be prudent in PJM's view.

Notably, these subsidies have been excluded from the MOPR previously as part of the competitive entry exemption under PJM's tariff prior to the *NRG* remand. These subsidies are not provided on the basis of the recipient's business model to produce electricity, but rather are aimed at incentivizing local development in an area.

Also, PJM proposes excluding wind and solar RECs to the extent the seller sells the REC to a purchaser that is not required by a state program to purchase the REC, and that purchaser does not receive any state financial inducement or credit for the purchase of the REC. This exclusion is reasonable as it ensures only those subsidies provided through a state program, rather than through a voluntary bilateral arrangement, is considered a Material Subsidy under the rules. Indeed, PJM views this as more in the nature of a clarification. RECs were developed, and still are largely (if not almost entirely) used, as a means for load-serving entities to demonstrate compliance with mandatory state renewable portfolio standard programs. While the market value of RECs may fluctuate, their purchase by Load Serving Entities ("LSEs") (as an alternative to the LSE building its own renewable generator) is mandated by the state, and is designed by state renewable portfolio standard ("RPS") programs as a means to flow revenues to the state-desired renewable resources so as to help meet statutory RPS requirements for renewable generation share. In recent years, however, a parallel market has arisen for voluntary REC purchases, unrelated to RPS mandates, by non-LSEs. For the most part, this demand is from private corporations pursuing adopted missions to reduce the corporation's environmental impacts. Because these purchases do not arise from a state mandate, they are reasonably distinguished from the large bulk of REC purchases made to show compliance with state RPS mandates, and thus are reasonably not considered state subsidies.[40]

c. "Entitled To" Test

The material resource must be *"receiving or entitled to receive"* a Material Subsidy. The concept of when a resource is receiving or going to receive a Material Subsidy was the topic of much discussion during the stakeholder sessions PJM held in the wake of the June 29 Order. Some argued that the terminology PJM had proposed in its April 9 filing—including "seeking"—was vague and could cause resources in states that were in the beginning stages of considering programs to provide out-of-market support to certain resources to get swept up in PJM's rules. As discussed in more detail below, PJM's rationale for using the terminology "entitled to" is to ensure that only those material resources which have or will have a subsidy at the time of the BRA, or by the time of the Delivery Year, are considered as having a Material Subsidy and are subject to the MOPR or are eligible for the RCO.

PJM also heeded feedback that some resources may be "entitled to" a subsidy but choose to forgo such subsidy and thus also should not be subject to the MOPR. Acknowledging this could be an issue for some, PJM proposes to allow such Material Resource to declare affirmatively that although entitled to a subsidy it will not take such subsidy and thus will not be considered a resource with a Material Subsidy.

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40 PJM's pro forma Tariff language, however, attaches two reasonable protections to this distinction. First, since most ultimate REC purchases are for Renewable Portfolio Standard ("RPS") compliance, generator REC sales to an intermediary are presumed to be for ultimate purchase to meet RPS mandates. Second, if a purchase is not for RPS requirements, but is connected to the purchaser's receipt of some other state financial inducement or credit for the purchase of the REC, then the generator's REC sale is properly considered a form of state subsidy.

The Capacity Market Seller must be "entitled to" a Material Subsidy for a Material Resource or have received a Material Subsidy for its material resource in the past and has not cleared an RPM Auction since it received such subsidy.[41] In the April 9 Filing, PJM proposed that any resource for which the seller "formally or informally, directly or indirectly, seeks, recovers, accepts, or receives" a Material Subsidy would be a Capacity Resource with Actionable Subsidy.[42] However, during the stakeholder discussions on how best to respond to the June 29 Order, several stakeholders raised concerns that the proposed language was vague and potentially unworkable. Thus, to provide greater clarity but still retain a broad scope, PJM is proposing that once a seller is "entitled to" a Material Subsidy for a resource, such resource may be a Capacity Resource with Actionable Subsidy and be subject to MOPR or eligible for the RCO option. PJM's proposed use of "entitled to" removes much of the subjectivity inherent in the prior language, e.g., the determination of when a seller may be "informally" "seeking" a subsidy. Under this approach, whenever a seller has a legal right or a legal claim to the subsidy, regardless of whether the seller has yet to actually receive the subsidy, the resource is a Capacity Resource with Actionable Subsidy.

An example can help describe how this provision would be applied. A bill recently signed into law in New Jersey assigns to the Board of Public Utilities the task of identifying whether particular New Jersey resources need a subsidy and if so the size of that subsidy. As a timing matter, the BPU may not complete its examination by the time of the upcoming August 2019 auction because specific units many not have been

41 *See* pro forma PJM Tariff, Attachment DD, section 5.14(h)(ii)(B).

42 *See* April 9 Filing, Option B, at proposed PJM Tariff, Attachment DD § 5.14(h)(2)(b).

identified. Thus because, at least as to that auction, it cannot be said that their "entitlement" to a subsidy has been determined. As such, the Material Subsidy definition would not apply to the New Jersey resources for this auction but would apply for subsequent BRAs and Incremental Auctions once the BPU has determined a specific resource(s) is entitled to a subsidy.

However, PJM is proposing that not all resources for which a seller is entitled to receive a Material Subsidy will be treated as Capacity Resources with Actionable Subsidy and thus subject to the MOPR. If a seller is willing to forego receiving all Material Subsidies associated with a resource for the relevant Delivery Year, then that resource will not be treated as a Capacity Resources with Actionable Subsidy and will not be subject to the MOPR.[43] Sellers will need to affirmatively inform PJM of this choice no less than thirty days before the commencement of the relevant BRA.[44] This is reasonable, as it allows the seller to weigh the impacts of being subject to the MOPR against the expected out of market revenue stream to which it is entitled. Sellers should be free to make such a business decision.[45]

43 *See* pro forma PJM Tariff, Attachment DD, section 5.14(h)(vi)(A).

44 *See* pro forma PJM Tariff, Attachment DD, section 5.14(h)(vi)(B).

45 *See* pro forma PJM Tariff, Attachment DD, section 5.14(h)(vi). In addition, even if the seller may no longer be "entitled to" a subsidy for a resource, the resource may nonetheless be treated as a Capacity Resource with Actionable Subsidy if the Capacity Market Seller received a Material Subsidy for such resource since the resource last cleared an RPM Auction. This is because subsidies can go toward construction and project investments as well as general going-forward costs, and thus affect the amount of capacity revenue a resource requires to be economic. Further, qualifying such resources as Capacity Resources with Actionable Subsidies ensures that Capacity Market Sellers cannot circumvent the MOPR by, for example, constructing a resource based on state subsidies, operating it for a year or two without receiving any more subsidies, and then trying to clear an RPM Auction on a going-forward cost offer. The same logic supports subjecting

Accordingly, only those resources that can reasonably rely on receiving a subsidy or that have received a subsidy since they last cleared an RPM Auction will be captured in the definition of Capacity Resource with Actionable Subsidy.

3. Material Subsidies – Federal

PJM intends that a resource with a federal subsidy will be subject to the MOPR under certain circumstances. Specifically, PJM proposes to exclude all federal subsidies that were enacted into law prior to March 21, 2016. This date is the refund effective date established by the Commission in its June 29 Order with respect to the Calpine complaint case in Docket No. EL16-49, which has been consolidated with this proceeding. For legislation enacted on or after March 21, 2016, or for new federal subsidies implemented after March 21, 2016, PJM will apply the MOPR to resources receiving subsidies under such legislation or programs *unless* the legislation contains an express proviso that such legislation should be implemented notwithstanding rules enacted pursuant to the FPA. These conditions are explained below.

a. Rationale for the Cut-off Date

The FPA provides that the Commission establish a refund effective date when considering a complaint about a rate, term or condition of transmission service (i.e., a tariff rule) or when the Commission conducts an investigation of a tariff rule on its own initiative so that market participants are on notice that the rule may change prospectively from that time.[46] As the Calpine complaint proposed application of the MOPR to all

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to the MOPR a resource that is excluded from RPM under the RCO option, receives subsidies that it invests in the resource (e.g., nuclear turbine replacement), and then re-enters RPM.

46 16 U.S.C. § 824c(b); *see also Port of Seattle v. FERC*, 499 F.3d 1016, 1030 (9th Cir. 2007).

resources for all reasons,[47] it is appropriate to accept that date as a cut-off for the application of the MOPR to legislation adopting federal subsidies which, prior to that date, were not included in consideration of PJM's rules. Importantly, this is different than state subsidies which, albeit limited by certain threshold considerations such as materiality, have been subject to mitigation rules in PJM's capacity market as established pursuant to the FPA.

In its June 29 Order, the Commission asked PJM and interested parties to consider whether (and, implicitly, to what extent) the rules protecting the competitive outcomes of PJM markets necessary to ensure just and reasonable rates required by the FPA should also apply to federal subsidies.[48] PJM asserts the answer to that inquiry is yes under certain conditions including when the legislation was enacted and whether the legislation contemplated potential mitigation under the FPA (as described in the next subsection).

b. <u>Rationale for inclusion of an express statement to remove the federal subsidy from MOPR</u>

PJM explained in its April 9 Filing that it proposed to exclude federal subsidies out of deference to the notion that the Commission's jurisdiction under the FPA would not extend to countermand other acts of Congress.[49] PJM continues to ascribe to this view. However, PJM posits deference to other federal legislation and related programs can be respected while also ensuring, in appropriate circumstances, that Congressional intent, as embodied, on one hand, in the FPA, and, on the other hand, specific Congressional legislation enacting subsidies, can be harmonized going forward. This

47 Calpine Complaint, Docket No. EL16-49-000, at 2.

48 June 29 Order at P 167.

49 April 9 Filing at 71; Answer of PJM Interconnection, L.L.C., Docket Nos. ER18-1314-000, et al., at 27 (May 25, 2018) ("May 25 Answer").

balance can be achieved by looking to new federal programs that are enacted pursuant to federal legislation unless such legislation contains an express proviso that such legislation should be implemented notwithstanding rules enacted pursuant to the FPA. In short, although it is not reasonable to have expected the drafters of federal legislation in years past (dating back to at least passage of the Price Anderson support for commercial nuclear generation) to have specifically reconciled the application of that legislation to the setting of clearing prices in the organized markets pursuant to the FPA, it is not unreasonable to expect Congressional drafters to address this conflict in future legislation. This future expectation is especially reasonable in light of recent Court decisions clarifying the authority of the Commission under the FPA to address the impacts of such subsidies.[50] As a result, PJM proposes that future legislation would be examined to see if Congress expressly limited the Commission's ability to address the price suppressive effects of such subsidies on the determination of just and reasonable rates. If Congress expressly speaks to this subject then the application of MOPR to that newly created subsidy would give way. If Congress does not, then FERC's authority to mitigate the impacts of the subsidy on the determination of just and reasonable rates would remain in place.

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50 *Elec. Power Supply Ass'n v. Star*, Nos. 17-2433 & 17-2445, 2018 U.S. App. LEXIS 25980, at *16-17 (7th Cir. Sept. 13, 2018) (upholding Illinois Zero Emission Credit program,); *Coalition for Competitive Elec. v. Zibelman*, No. 17-2654-cv, 2018 U.S. App. LEXIS 27605 (2d Cir. Sept. 27, 2018) (upholding New York Zero Emission Credit program).

c. Resources with Federal Subsidies that are Subject to MOPR are not Eligible for the RCO

PJM proposes that, should a resource receive a Material Subsidy stemming from a federal program, and that resource also meets the criteria for a Capacity Resource with Actionable Subsidy, then it should be subject to the MOPR. However, unlike Capacity Resources with Actionable Subsidies stemming from a state subsidy, it is not appropriate or necessary to allow federally subsidized Capacity Resources with Actionable Subsidies to be eligible to elect the RCO. This limitation is just and reasonable and not unduly discriminatory for the following reasons.

The impetus for the Commission suggesting in its June 29 Order that PJM consider a bifurcated (part auction-based and part carved-out) capacity construct was to explore ways to accommodate the deregulated states wishing to support certain resources within their states in order to advance particular state policy interests. A necessary element of such accommodation is the fact that resources electing the RCO would be compensated by the state (subject to the Commission rate authority under the FPA, as discussed in detail below) and not through PJM's wholesale market.

This is an important point because it is not clear how RCO would work from a practical standpoint if applied to federal programs. First, such subsidy would likely not differentiate between the states but would be nationwide in application. Thus, there is no geographic area or specific corresponding load to carve out. Also, it is not clear how the government would compensate a federally subsidized resource which elected RCO. PJM expects that, to the extent it is an administrative act, the governmental entity might look to PJM to provide such compensation. As such, PJM might have no choice but to file a new rate scheme to compensate federally subsidized resources to the extent such resources are not compensated (at all or in part) through PJM's markets. Thus, unlike under a state subsidy program where the state's consumers are allocated the capacity costs of the carved-out resource, PJM expects that under a federal subsidy program, it will still be PJM customers – likely across the RTO Region – which would be allocated the costs. Given this practical reality, a carve-out is neither necessary or appropriate for a federally subsidized resource that is subject to MOPR.

And, while under such approach it is more likely the resource would not clear and any compensation would be through a make-whole type payment rather than through a capacity payment (in other words, PJM customers would still pay) at least the resulting clearing price would remain competitive and not be artificially suppressed by federally subsidized Capacity Resources with Actionable Subsidies. Thus, there is no reason to allow for a carve out, because either way PJM expects the resource would be compensated through the PJM Tariff.

4. Eligible Self-Supply Entities are Exempt from the Definition of Capacity Resource with Actionable Subsidy

PJM is proposing one categorical exemption from the definition of Capacity Resource with Actionable Subsidy, and thus an exemption from the MOPR—the Self-Supply Exemption. The proposed Self-Supply Exemption closely follows the categorical exemption the Commission previously accepted for application of the MOPR, in that such exclusion appropriately balances between protecting against price suppression while avoiding interference with long-standing capacity procurement business models.

Just like the Self-Supply Exemption the Commission accepted in Docket No. ER13-535, PJM is proposing to limit the exemption to "Public Power Entities," which include cooperatives and municipal utilities, "Single Customer Entities," and "Vertically

Integrated Utilities." As a general matter, these entities are appropriately excluded, because their traditional business models for capacity procurement do not give rise to concerns related to artificial price suppression. Indeed, the Commission has found that "[a]n uneconomic new entry strategy by a vertically-integrated utility, for example, poses a substantial risk of increasing its net costs," and, therefore, "these entities are unlikely to depend on costly strategies to address the non-self-supply portion of their portfolio."[51]

Consistent with Commission precedent, PJM is proposing *not* to give a blanket exemption to self-supply entities, but is establishing a net short and net long thresholds to ensure that the seller is not presented with an "unacceptable opportunity" to suppress clearing prices. PJM is proposing no changes to the thresholds the Commission approved in Docket No. ER13-535, and which PJM and its stakeholder re-evaluated and reaffirmed last year.

While, as discussed below, the scope of MOPR is proposed to be expanded to cover existing as well as new resources, PJM is retaining the scope of the net short and net long thresholds to apply only to new resources. In other words, a Self-Supply Load Serving Entity ("LSE") may qualify all its existing resources for the Self-Supply Exemption and those resources will not be subject to MOPR, regardless of any Material Subsidies. That is because application of net short and net long thresholds is unworkable under a scheme that looks at existing as well as new resources. For example, if a seller is in fact, net long on capacity (i.e., the LSE may have such a relatively large amount of excess capacity that it may seek to "dump" capacity on the BRA, pushing down capacity prices in the process), it is not possible to determine which resources in the seller's

51 *PJM Interconnection, L.L.C.*, 143 FERC ¶ 61,090, at P 111.

portfolio are the "excess" capacity not needed to meet the needs of its retail demand and thus should be designated as subject to MOPR and which resources are needed to meet load and should not be subject to MOPR. Any such determination would be inherently subjective and arbitrary. By contrast, only reviewing to see whether new resources would violate the stated thresholds fulfills the purpose of these thresholds — to prevent anti-competitive behavior. For this reason, the Commission has found "that, as a general matter, providing exemptions for resources properly designated as self-supply when they meet suitable net-short and net-long thresholds is reasonable."[52]

B. Process for Capacity Market Sellers to Self-Certify as Capacity Resource with Actionable Subsidy

Taking advantage of the fact that sellers know best whether their Capacity Resources register as a Capacity Resource with Actionable Subsidy, PJM is proposing that sellers "self-certify" the status of their resources.[53] PJM envisions that this certification process would be accomplished electronically, as a "check the box" line item when the seller specifies whether it owns a Capacity Resource with Actionable Subsidy and must be done no later than 150 days prior to the relevant RPM Auction. Specifically, for each Capacity Resource offered into an RPM Auction, the seller would "certify

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52 *PJM Interconnection, L.L.C.*, 143 FERC ¶ 61,090, at P 108 (2013) ("May 2013 Order"), *reh'g denied*, 153 FERC ¶ 61,066, at P 35 ("In traditionally-regulated states, a large majority of load is typically satisfied by generation owned by the load serving entity and recovered through state cost of service rates. Because of this financing model, the competitive entry exemption is not applicable to resources developed through that model. PJM, therefore, appropriately developed the self-supply exemption to determine under this financing model whether an investment in new generation is consistent with a competitive market.") (2015).

53 *See generally* pro forma Tariff, Attachment DD, section 5.14(h)(iii)(A).

whether or not such Capacity Resource is a Capacity Resource with Actionable Subsidy.".[54]

PJM proposes that such self-certifications will be made in "good faith." As such, in lieu of requiring seller's to provide supporting information along with the certification, PJM and the IMM shall have the authority to request information supporting a seller's certification.[55] This will provide PJM, with input and advice of the Independent Market Monitor ("IMM"), with the ability to verify the accuracy of a Capacity Market Seller's representation. To provide Capacity Market Sellers with sufficient certainty prior to the relevant RPM Auction, PJM will provide notification that it disagrees with a Capacity Market Seller's registration (or lack thereof) of a Capacity Resource with Actionable Subsidy no later than sixty days prior to the commencement of the relevant RPM Auction. Sellers will have an ongoing obligation to promptly provide PJM and the IMM information, upon request.

A resource's status as a Capacity Resource with Actionable Subsidy shall continue unless and until the seller notifies PJM of a change in the resource's status (i.e., it is no longer entitled to a Material Subsidy or any of the other criteria for Actionable Subsidy are changed). Such status also will change it PJM determines that fraud or material misrepresentation occurred with regard to the resource's current status, or the Commission orders a change in status.[56] Sellers will have a continuing obligation to notify PJM and the IMM of any material changes in the qualifications of the resource.[57]

54 *See* pro forma Tariff, Attachment DD, section 5.14(h)(iii)(A).

55 *See* pro forma Tariff, Attachment DD, section 5.14(h)(iii)(A).

56 *See* pro forma Tariff, Attachment DD, section 5.14(h)(iii)(B).

57 *See* pro forma Tariff, Attachment DD, section 5.14(h)(iii)(A).

C. The Minimum Offer Price Rule

In its April 9 Filing, PJM proposed a MOPR that would apply to both new and existing resources but proposed four categorical exemptions. In its June 29 Order, the Commission found the proposed MOPR "would [] prevent some resources that receive Material Subsidies from suppressing capacity market prices."[58] But, the Commission rejected the proposal, on the grounds that "PJM has not provided 'a valid reason for the disparity' among resources that receive out-of-market support through RPS programs, which are exempt from the MOPR-Ex proposal, and other state-sponsored resources, which are not."[59] Nonetheless, the Commission made a preliminary finding that the replacement rate should include "[a]n expanded MOPR, with few or no exceptions, [which] 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."[60]

Accordingly, PJM is proposing here expanded MOPR rules to address the impact of state subsidies on the capacity market. PJM's MOPR would apply only to a Capacity Resource with Actionable Subsidy (and exclude exempted self-supply LSE). Under PJM's MOPR proposal, the MOPR Floor Offer Price will be established using either default cost and expected revenue values for each resource type, or at the seller's election, the resource's *actual* costs and expected revenues. In other words, PJM is not

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58 June 29 Order at P 100.

59 June 29 Order at P 100 (quoting *Black Oak Energy, LLC v. FERC*, 725 F.3d 230, 239 (D.C. Cir. 2013)).

60 June 29 Order at P 158.

eliminating the Unit-Specific Exception,[61] but rather is simply incorporating it into the process for establishing the minimum offer price for a resource.

1. MOPR Floor Offer Price for Capacity Resources with Actionable Subsidy

Capacity resources subject to the Minimum Offer Price Rule cannot submit offers into an RPM Auction that fall below the MOPR Floor Offer Price for that resource. The determination of the MOPR Floor Offer Price for each resource will depend on whether: (1) the resource is a Generation Capacity Resource or a Demand Resource; (2) the resource has previously cleared in an RPM Auction; and (3) the resource is returning to the market after electing the RCO option. As before, the MOPR Floor Offer Price generally establishes the *lowest* price the seller may offer the resource, while the Market Seller Offer Cap generally continues to establish the *highest* price.[62] Further, as before, sellers will be able to offer their resources at level no lower than the resource's default or actual costs.

a. MOPR Floor Offer Prices for Capacity Resources that have Never Cleared Any RPM Auction

i. MOPR Floor Offer Prices for Generation Resources that have never cleared any RPM Auction

Historically, MOPR has applied only to new entry Generation Capacity Resources, and has required such resources to offer no lower than either the default net cost of new entry for the applicable resource types, as stated in the tariff, or their unit-

61 Under the current MOPR rules, the Unit Specific Exception allows a MOPR applicable resource to show that its actual costs are lower than the defined MOPR Floor Offer Price and thus, such resource is permitted to offer at that lower price.

62 Any seller that wishes to submit an offer above the Market Seller Offer Cap must follow the procedures set forth in Tariff, Attachment DD, section 6.

specific costs, including construction costs, as determined through the Unit-Specific Exception.[63] While the focus has been on new entry, the MOPR has long applied to all resources that have never cleared an RPM Auction, because "[a] resource could lose its status as a Planned Generation Capacity Resource [i.e., by going in to service] before the resource has cleared a capacity auction, thereby enabling an uneconomic resource to bypass the MOPR and successfully and artificially suppress capacity prices."[64] Accordingly, the Commission found it would be "unreasonabl[e to] remove the offer floor before the resource has demonstrated that it is needed by the market."[65] Thus, three types of generation Capacity Resources with Actionable Subsidies that have never cleared an RPM Auction would be subject to this MOPR Floor Offer Price: (1) planned resources; (2) resources that have achieved operation;, and (3) resources that have been excluded from RPM under the RCO option and that are seeking to enter RPM if and when the resource no longer is receiving the subsidy.

Consistent with this purpose, PJM is proposing to retain the MOPR's historical approach for Capacity Resources with Actionable Subsidies that have never cleared an RPM Auction by setting their MOPR Floor Offer Price based on their costs of constructing the facility. Accordingly, such resources may offer no lower than the resource's cost of new entry ("CONE") net of the resource's estimated energy and

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63 *See, e.g.*, Tariff, Attachment DD, section 5.14(h).

64 *PJM Interconnection, L.L.C.*, 135 FERC ¶ 61,022, at P 174 (2011) ("ER11-2875 April Order"), *order on reh'g*, 137 FERC ¶ 61,145 (2011), *aff'd sub nom. N.J. Bd. of Pub. Utils. v. FERC*, 744 F.3d 74 (3d Cir. 2014).

65 ER11-2875 April Order at P 174.

ancillary services markets revenues.[66] The CONE for these resources will be based on their construction and going-forward costs, either a default value based on new greenfield construction for the resource type or a resource-specific determination that utilizes the same criteria, parameters, and evaluation processes under which PJM have historically approved Unit-Specific Exception requests.

As Mr. Keech explains,[67] PJM proposes to include in the Tariff tables of initial default values,[68] to be adjusted annually as discussed below. The Tariff-stated values will be used for the 2022/2023 Delivery Year. These values are based on information from a data base of the National Renewable Energy Laboratory ("NREL").[69] The data relied on includes the overnight capital costs and the fixed operating and maintenance expense ("FOM") for nuclear, coal, hydro, solar photovoltaic, onshore wind, and offshore wind technologies as projected for 2022.[70] Combined cycle and combustion turbine levelized annual costs are based on 2021/2022 BRA Planning Parameters escalated to 2022/2023.[71]

While this preliminary analysis is well-supported and results in values that would be just and reasonable for the limited purpose of setting default values that will merely act as the minimum offer floor only in the event the seller does not elect to utilize a

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66 Pro forma Tariff, Attachment DD, section 5.14(h)(iv)(A)(1)(a). In no event shall the offer exceed the Market Seller Offer Cap unless the seller specifically requests an exception to the cap in accordance with the Tariff.

67 Keech Aff. ¶¶ 17-25.

68 *See id.* ¶ 17.

69 *See NREL Annual Technology Baseline*, National Renewable Energy Laboratory, https://atb.nrel.gov/ (last visited Oct. 1, 2018).

70 Keech Aff. ¶ 18.

71 *See id.* ¶ 20.

resource-specific cost-based rate, PJM does not view this analysis as the last word. PJM proposes to review and re-evaluate these default values as part of the quadrennial review of the VRR Curve and CONE values.[72] PJM has long followed this periodic review practice to update the default MOPR Floor Offer Prices stated in the Tariff.

Additionally, Mr. Keech explains that, to account for the dynamic nature of costs, for subsequent Delivery Years, PJM will adjust annually those default values using the same Applicable BLS Composite Index used to adjust the CONE value of the VRR curve[73] and post those updated values 150 days before the applicable RPM Auction.[74]

However, default values are only half the equation. To determine the applicable default MOPR Floor Offer Price, expected revenues from the PJM energy and ancillary services markets must be subtracted from the default Avoidable Cost Rates. PJM has estimated the expected energy and ancillary services markets ("E&AS") revenue offset for each resource type based on the type's historical three-year average of such revenues across the PJM region.[75] The default E&AS revenue offsets are presented in Table 1 below. The default MOPR Floor Offer Price for each resource type will be the CONE net of E&AS revenues.

Table 1 details, by generation resource type, cost of new entry, the offset of estimated E&AS revenues, and the resulting MOPR Floor Offer Prices.

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72 *See* pro forma Tariff, Attachment DD, sections 5.14(h)(iv)(A)(1)(a) and 5.14(h)(iv)(A)(2)(a). Also, PJM will continue to work with its stakeholders and the IMM to refine, as needed, the values it has included in the present filing.

73 *See* pro forma Tariff, Attachment DD, section 5.14(h)(iv)(A)(1)(a) and pro forma Tariff, Attachment DD, section 5.14(h)(iv)(A)(2)(a).

74 Keech Aff. ¶ 22.

75 *See id.* ¶ 21.

Table 1: Estimated New Entry Default MOPR Floor Offer Prices

	Default MOPR Floor Offer Prices, $/ICAP MW-day[76]		
Planned Resource Type	**Cost of New Entry**	**Estimated E&AS Revenue Offset**	**MOPR Floor Offer Prices net of E&AS Revenues**
Nuclear	$1,817	$366	$1,451
Coal	$1,067	$45	$1,023
Combined Cycle	$523	$85	$438
Combustion Turbine	$380	$26	$355
Hydro	$1,177	$111	$1,066
Solar PV	$627	$240	$387
Onshore Wind	$3,670	$1,180	$2,489
Offshore Wind	$5,507	$1,180	$4,327

It is important to note these are *default* values. If a seller believes that the actual costs of its resource are lower than the default values, the seller may request determination of a resource-specific MOPR Floor Offer Price. In the past, this review was known as the "Unit-Specific Exception," but now PJM is proposing to use such process to establish resource-specific MOPR Floor Offer Prices; in other words, PJM is simply re-naming the historic Unit-Specific Exception as the resource-specific MOPR Floor Offer Price. To be clear there is no substantive difference between a Unit-Specific Exception and a resource-specific MOPR Floor Offer Price; both establish the minimum price at which a seller may offer the resource based on the specific costs of that resource.

76 The MOPR Floor Offer Prices are expressed in dollars per Installed Capacity ("ICAP") MW-day, where the ICAP MW value for Solar PV, Onshore Wind and Offshore Wind is assumed to be 42.0%, 14.7%, and 26.0%, respectively, of the nameplate rating of these resource types.

Thus, in a request for such resource-specific determination, consistent with the historic MOPR provisions,[77] a seller must use the following financial modeling assumptions:

> (i) nominal levelization of gross costs, (ii) asset life of 20 years, (iii) no residual value, (iv) all project costs included with no sunk costs excluded, (v) use first year revenues, and (vi) weighted average cost of capital based on the actual cost of capital for the entity proposing to build the Capacity Resource.[78]

The seller must also provide supporting documentation for project costs.[79] The seller shall also provide any additional supporting information reasonably sought to evaluate the request.

ii. MOPR Floor Offer Prices for Planned Demand Resources

Because, as Mr. Keech explains, determining costs to develop new Demand Resources is not feasible, PJM proposes to apply the historical average of all Demand Resource offers submitted in the last three BRAs for the Locational Deliverability Area ("LDA") in which the Demand Resource is located as the MOPR Floor Offer Price for Demand Resources that have never previously cleared any RPM Auction.[80] This historical three-year average value provides a good approximation of the costs for Demand Resources and therefore is analogous to the default CONE values applicable to

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77 *See* ER11-2875 April Order at P 43; *see also* Tariff, Attachment DD § 5.14(h).

78 *See* pro forma Tariff, Attachment DD, section 5.14(h)(iv)(B)(2).

79 *Id.*

80 *See* Keech Aff. ¶¶ 24-25.

Generation Capacity resources.[81] For each RPM Auction, PJM will post these historical average values at the same time it posts all other MOPR Floor Offer Prices.[82]

For the upcoming BRA for the 2022/2023 Delivery Year, the three-year historical average offer prices for Demand Resources, by LDA, are shown in the table below.

Table 2: Three-Year Historical Average DR Offer Prices, By LDA

LDA (Rest Of)	Average
ATSI	$48.26
ATSI-CLEVELAND	$47.91
BGE	$67.34
COMED	$59.63
DAY	$31.98
DEOK	$28.79
DPL-SOUTH	$63.09
EMAAC	$59.82
MAAC	$54.33
PEPCO	$50.97
PPL	$58.79
PSEG	$62.83
PS-NORTH	$53.46
RTO	$50.95
Entire RTO	**$53.69**

Based on these values, the MOPR Floor Offer Price for Planned Demand Resources will range from $28.79 to $67.34, depending on the LDA in which the resource resides.

b. MOPR Floor Offer Prices for Capacity Resources that have cleared an RPM Auction

i. MOPR Floor Offer Prices for Existing Generation Resources

To accommodate the expansion of the MOPR to cover existing resources, PJM is proposing separate MOPR Floor Offer Price provisions to establish the appropriate

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81 Keech Aff. ¶ 25.

82 *See* pro forma Tariff, Attachment DD, section 5.14(h)(iv)(A)(1)(b).

minimum price at which existing, subsidized resources may offer into RPM Auctions. Thus, generation Capacity Resources with Actionable Subsidies that have previously cleared an RPM Auction should be allowed to offer no lower than the resource's Avoidable Cost Rate net of the resource's estimated energy and ancillary services markets revenues.[83] Unlike for resources that have not cleared an RPM Auction, the market has demonstrated a need for these resources (by clearing them), and therefore the Avoidable Cost Rate for such resources reflects their going-forward costs, and not their construction and development costs. The seller may elect to use a resource-type default Avoidable Cost Rate or a resource-specific cost rate. Just like for new entry resources, PJM proposes to include in the Tariff default going-forward cost values for existing generation resources,[84] use those values for the 2022/2023 Delivery Year BRA, and for subsequent Delivery Years, annually adjust those values using the Applicable BLS Composite. The adjusted values will be posted on its website in advance of each RPM Auction.[85]

As Mr. Keech explains, PJM determined the default values based on information from a database of the Environmental Protection Agency ("EPA").[86] Because the EPA's data are presented in 2011 dollars, PJM needed to escalate the value to 2022/2023 dollars, as that is the relevant Delivery Year for the upcoming BRA. To do so, first PJM escalated them from 2011 to 2017 by historical year by year escalation using the

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83 *See* pro forma Tariff, Attachment DD, section 5.14(h)(iv)(A)(2). In no event shall the offer exceed the Market Seller Offer Cap unless the seller specifically requests an exception to the cap in accordance with the Tariff.

84 *See* pro forma Tariff, Attachment DD, section 5.14(h)(iv)(A)(2)(a).

85 *See* pro forma Tariff, Attachment DD, section 5.14(h)(iv)(A)(2)(a).

86 Keech Aff. ¶ 29.

Applicable BLS Composite Index.[87] PJM determined 1.026% to be the 10-year average escalation rate for the 2008-2016 period. Combined, Mr. Keech explains that, these two escalations (for 2011-2017 and for 2017-2022) are equivalent to a factor of 1.254.[88] Thus, to arrive at the values stated in the above table, PJM multiplied the 2011 EPA values by 1.254.

As with the new entry default values, PJM's preliminary analysis is well-supported and results in values that would be just and reasonable for the limited purpose of setting default Avoidable Cost Rate values that will merely act as the minimum offer floor only in the event the seller does not elect to utilize a resource-specific cost-based rate. PJM proposes to review and re-evaluate these default values as part of the quadrennial review of the VRR Curve and CONE values.[89]

In addition, PJM will annually adjust the default values for existing generation resources using the same Applicable BLS Composite Index. Table 3 below presents the default Avoidable Cost Rates for existing generation resources.

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87 *See* pro forma Tariff, Attachment DD, section 5.14(h)(iv)(A)(2)(a); *see also* Keech Affidavit ¶ 31.

88 Keech Aff. ¶ 31.

89 Keech Aff. ¶ 23. As noted, PJM will continue to work with stakeholders and the IMM to refine these values prior to the MOPR Floor Offer Price posting requirement for the upcoming BRA, as needed.

Table 3: Existing Resource Default MOPR Floor Offer Prices

Existing Resource Type	Avoidable Cost Rates in $/ICAP MW-day[90]
Nuclear - single	$631
Nuclear - dual	$593
Coal	$171
Combined Cycle	$86
Combustion Turbine	$57
Hydro	$0
Pumped Hydro	$0
Solar PV	$0
Wind Onshore	$0

As can be seen from the table, the default Avoidable Cost Rates for most existing generation resource types is low or, in the case of certain resource types, zero.[91] Mr. Keech testifies that while the default Avoidable Cost Rate values for hydro, pumped hydro, solar photovoltaic, and onshore wind are not equal to zero, "PJM proposes to set the default Avoidable Cost Rate values for these resources at $0 because even the most conservative (low-end) estimate of net E&AS revenues . . . for these resources . . . would result in negative default MOPR Floor Offer Prices."[92] This provides sellers of such resources great flexibility in determining their Sell Offers.

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90 The Avoidable Cost Rate values for Hydro, Pumped Hydro, Solar PV and Onshore Wind were estimated to were estimated to be $66/ICAP MW-day, $25/ICAP MW-day, $168/ICAP MW-day and $457/ICAP-MW day, respectively, which are significantly lower than the relevant net E&AS revenues for these resource types as listed in Table 1.

91 *See* Keech Aff. ¶ 28.

92 Keech Aff. ¶ 28.

However, if a seller believes that the default floor price overstates the actual costs of its resource, the seller may request a resource-specific Avoidable Cost Rate determination. Because the subject resource would be an existing resource and only its going-forward costs would need to be evaluated, the former Unit-Specific Exception procedures would not be applicable. Rather, the seller would need to follow the procedures in Tariff, Attachment DD, section 6.8, under which PJM and the IMM have long calculated Avoidable Cost Rate offer caps to prevent the exercise of market power. The avoidable cost components laid out in section 6.8, net of expected E&AS revenues, would allow for the establishment of a cost-based MOPR Floor Offer Price specific to the resource.

ii. MOPR Floor Offer Prices for Existing Demand Resources

PJM proposes that the MOPR Floor Offer Price for existing Demand Resources be zero. As stated As Mr. Keech states in his affidavit, there is no clear method to determine the Avoidable Cost Rate for Demand Resources in practice today.[93] Further, beyond the initial costs associated with developing a customer contract and installing any required hardware or software needed to effectuate a load reduction (i.e., costs that would apply to Planned Demand Resources), PJM could not identify any meaningful avoidable costs that would be incurred by an existing Demand Resource that would result in a MOPR Floor Offer Price greater than zero.[94]

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93 *See* Keech Aff. ¶ 24.

94 *See* pro forma Tariff, Attachment DD, section 5.14(h)(iv)(A)(2)(b). The MOPR Floor Offer Price represents a minimum allowable offer. Therefore, any Capacity Market Seller wishing to offer at a higher price can do so, subject to the Market Seller Offer Cap.

c. MOPR Floor Offer Prices for Capacity Resources Re-entering RPM from the RCO

All resources leaving the RCO for RPM will be subject to the MOPR. As discussed below, while such resources are only allowed to enter RPM on the condition that they are no longer entitled to a Material Subsidy, such resources nonetheless qualify as Capacity Resources with Actionable Subsidy.[95] Resources that are re-entering RPM, i.e., resources that have previously cleared an RPM Auction, will have a MOPR Floor Offer Price that reflects their going-forward costs at the time of the RCO election and reflects project investment that occurred while the resource was out of RPM.[96] Specifically, PJM is proposing that the MOPR Floor Offer Price for such resource is:

> the Avoidable Cost Rate for the Capacity Resource at the time the Capacity Market Seller elected for such resource to take the RCO option plus the highest annual amortized cost of project investment (i.e., Avoidable Project Investment Recovery) that occurred since the election of the RCO option, as determined in accordance with Tariff, the Attachment DD, section 6.8, where the Avoidable Cost Rate may be determined on a default basis in accordance with section 5.14(h)(iv)(A) or on a resource-specific basis in accordance with section 5.14(h)(iv)(B).[97]

By using the resource's going-forward costs at the time the seller opts to remove the resource from the market, the seller does not obtain any relative advantage (or disadvantage) toward clearing an auction by leaving RPM. Rather, the seller would be faced with the same base MOPR Floor Offer Price it considered when it opted for the RCO. To allow otherwise, would allow the impact of the subsidy to affect the

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95 Pro forma Tariff, Attachment DD, section 5.14(h)(ii)(B).

96 Pro forma Tariff, Attachment DD, section 5.14(h)(iv)(A)(3). As discussed above, resources that previously were under the Resource Carve Out option *and* have never cleared in an RPM Auction will have a MOPR Floor Offer Price determined based on all of the resource's costs, including construction costs.

97 Pro forma Tariff, Attachment DD, section 5.14(h)(iv)(A)(3).

competitiveness of the auction. The MOPR was designed to ensure that all resources compete at a common measure of their true going forward costs. To allow a unit that receives a subsidy that has an 'overhang' effect of allowing for a write down of a unit's capital costs to enter into the market without considering the impact of that past subsidy is to virtually guarantee discriminatory application of the MOPR and distorted results as between units that received a subsidy and those that did not.

In addition, PJM proposes that the base MOPR Floor Offer Price should be increased to reflect project investment costs incurred while the resource was outside of RPM. However, the offer floor will not include a lump sum of all project investment costs, but rather will include the "the highest annual amortized" value, as determined in accordance with the processes set forth in Tariff, Attachment DD, section 6.8. As described there, the amortized value equals project investment (or "PI")[98] times an annual recovery factor based on the age of the resource (or "CRF"). PJM proposes to determine this value for each year the resource is out of RPM, and utilize the highest value in that resource's MOPR Floor Offer Price.

It is reasonable to reflect project investment costs in the offer price for a number of reasons. First, had the resource not left the market, such cost would have been reflected in any non-subsidized cost-based offer, and thus, this is similar to the floor price for a subsidized resource which does not choose the RCO. Second, inclusion of such costs in the MOPR Floor Offer Price is analogous to requiring inclusion of all

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98 "PI is the amount of project investment completed prior to June 1 of the Delivery Year, except for Mandatory Capital Expenditures ("CapEx") for which the project investment must be completed during the Delivery Year, that is reasonably required to enable a Generation Capacity Resource that is the subject of a Sell Offer to continue operating or improve availability during Peak-Hour Periods during the Delivery Year." Tariff, Attachment DD, section 6.8.

construction costs in the MOPR Floor Offer Price for a resource that has achieved operation but has yet to clear an RPM Auction. The Commission found that to not require the offer price to reflect such costs could "enabl[e] an uneconomic resource to bypass the MOPR and successfully and artificially suppress capacity prices."[99] The same logic applies here, as the resource likely would not be economic without the subsidized project investment and it should not be allowed to "artificially suppress capacity prices" by ignoring such costs.

D. Resource Carve-Out Option

As a complement to the expanded MOPR, the Commission directed PJM to devise a means to allow subsidized resources to ensure obtaining a capacity commitment without clearing PJM's capacity market.[100] This approach, as proposed by PJM here, offers an FPA-compliant path to accept and limit the trade-off that comes from recognizing subsidized, and hence uneconomic, resources as PJM capacity, while maintaining a workably competitive market.

Consistent with the June 29 Order, the Resource Carve-Out option provides an avenue for a Capacity Market Seller of a Capacity Resource with Actionable Subsidy, to choose such resource to be carved out from the capacity market. Specifically, a Carved Out Resource, along with an associated load, would not obtain their commitment through PJM's capacity market, and neither would make nor receive payments from the capacity market. However, any Carved out Resource would continue to maintain an energy market must-offer obligation and also be eligible to participate in PJM's energy and

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99 ER11-2875 April Order at P 174.

100 June 29 Order at P 160.

ancillary services market. The must-offer obligation is necessary as such resources would be modeled as any other committed Capacity Resources and subject to the same Capacity Performance standards.

1. Difference between RCO and PJM's Existing Zonal FRR Rules

A fundamental difference between RCO and PJM's existing zonal FRR rules is how the resources and load are determined to be out of the PJM capacity market. That is, under PJM's zonal FRR rules, the load to be served and resulting capacity obligation is determined first, and then the FRR Entity develops a portfolio of resources with which to meet that obligation. Under the RCO, the carve-out stems from the identification of the supply resource first, and then the associated load needs to be defined. This is the fundamental difference.

Also, under zonal FRR, regulated states, public power and vertically integrated entities engaging in self-supply and zonal FRR regions ("Excluded Systems") have retained, or assumed, respectively the obligation to meet resource adequacy needs for an LSE zone from a portfolio of identified resources. Excluded Systems bring the load and resource diversity associated with their systems into the larger PJM system for the efficiency and reliability benefit of the whole.

In contrast, the decision to remove from the PJM market a single existing resource and associated load involves, by definition, a decision to subsidize an uneconomic resource[101] to preserve an attribute associated with this resource (jobs, zero carbon

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101 An Excluded System may or may not include an uneconomic resource (a resource that would not clear PJM's capacity market if it were to participate in that market), but experience demonstrates that many generation units that are part of an Excluded System are economic and would clear PJM's capacity market

emissions, etc.) that would be lost as the result of the unit closing. Similarly removing a single planned resource and associated load is driven by a decision to subsidize a unit that brings a desired attribute, but one whose new entry would not be supported by the prices offered in PJM's markets.

2. Eligibility and Election of the RCO

Only those resources that are subject to MOPR on the basis of having a state subsidy[102] are eligible to elect the Resource Carve Out. As explained in detail in sections II.A and B, a resource is subject to MOPR when it:

- ✓ is a Capacity Resource with Actionable Subsidy because it is a Material Resource entitled to a Material Subsidy;
- ✓ has not chosen to forsake the Material Subsidy to which it is entitled; and
- ✓ is not exempted as a result of being a self-supply entity.

To be clear, Capacity Market Sellers of resources that are still seeking out-of-market payments but not yet entitled to such payments would not be eligible to elect the RCO option. This is because there is no guarantee that such resource would receive a Material Subsidy at this stage and would, therefore, not be subject to the MOPR.

This eligibility requirement is narrowly tailored to address the Commission's underlying goal of accommodating states' right to pursue policy goals. Further, this limited eligibility for the RCO option is necessary to prevent potential market manipulation by entities that may own a fleet of resources. Specifically, this eligibility requirement limits buyer-side market power by preventing an entity that owns a fleet of

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without regard for the rate base treatment or long-term wholesale power supply contracts characterizing these units.

102 For the reasons explained above, PJM is limiting the RCO option only to non-self-supply exempted Capacity Resources with Actionable Subsidies from a state subsidy and not a federal subsidy.

resources from carving out unsubsidized and uneconomic resources from the capacity market in an attempt to lower overall clearing prices.

In addition, PJM proposes that only Annual Resources be eligible for the RCO option. This is because it would be challenging to determine an associated load for only a Summer Period Capacity Performance Resource or a Winter Period Capacity Performance Resource. Since load is annual, a seasonal resource could not be appropriately associated with a non-seasonal load. Further, allowing a seasonal resource to elect the RCO option would require that seasonal resource to be offered at a price of zero into the auction, but it may not clear if there is no matching resource from the opposite season. This would yield unworkable results for purposes of determining load credits for Seasonal Capacity Performance Resources that are carved out of the capacity market. Thus, a Seasonal Capacity Performance Resource with an Actionable Subsidy could elect the RCO option only if it is commercially aggregated with a Summer Period Capacity Performance Resource or a Winter Period Capacity Performance Resource, as applicable. Absent being commercially aggregated with a matching Seasonal Capacity Performance Reosurce, such resource with an Actionable Subsidy would not be eligible for the RCO option and be subject to the MOPR.

In order to elect the RCO option, a Capacity Market Seller of a Capacity Resource with Actionable Subsidy acknowledges that it agrees to forego all market revenues from PJM's capacity market. This affirmative act of election and, thus, acknowledgment by the resource owner will ensure that it makes informed decisions about the effect of being carved out from the capacity market. Administratively, PJM proposes that the Capacity Market Seller of an eligible Capacity Resource with Actionable Subsidy elect the RCO option by checking a box in "Capacity Exchange" (formerly known as eRPM, or any successor RPM application) affirming that it meets all the eligibility requirements described above no later than 30 days before commencement of the BRA. As with a Capacity Market Seller's registration of a Capacity Resource with Actionable Subsidy, PJM reserves the ability to review the truthfulness of the Capacity Market Sellers' representation.

3. Timing of Election and Duration of the RCO

Consistent with the timing for the capacity market Must-Offer exception request and the unit-specific MOPR exception, PJM proposes to require Capacity Market Sellers that own Capacity Resources with an Actionable Subsidy to elect the RCO option no later than 45 days before the BRA.[103] This will provide sufficient time for PJM to incorporate the Carved Out Resources in the planning parameters, which will provide Market Participants with advanced notice that certain resource units and associated load in specific Zones will be carved out of the capacity market. This advanced information is useful for Market Participants as they prepare and strategize bid offers prior to the BRA.

a. Election of the Resource Carve-Out Option

In addition to the election of the Resource Carve-Out Option, a Capacity Market Seller will be required to notify PJM of the UCAP MW amount that the resource owner seeks to carve out on an annual basis. The maximum unforced capacity ("UCAP") MW quantity for those Capacity Resources that elect the RCO option will be determined using the lower of the generation resources' EFORd calculated based on outage data for the 12 months ending September 30th prior to the Base Residual Auction or the 5 Year Average EFORd based on outage data for the 12 months ending September 30th prior to the BRA.

[103] *See* pro forma Tariff, Attachment DD, section 5.14(h)(vi)(B).

resources from carving out unsubsidized and uneconomic resources from the capacity market in an attempt to lower overall clearing prices.

In addition, PJM proposes that only Annual Resources be eligible for the RCO option. This is because it would be challenging to determine an associated load for only a Summer Period Capacity Performance Resource or a Winter Period Capacity Performance Resource. Since load is annual, a seasonal resource could not be appropriately associated with a non-seasonal load. Further, allowing a seasonal resource to elect the RCO option would require that seasonal resource to be offered at a price of zero into the auction, but it may not clear if there is no matching resource from the opposite season. This would yield unworkable results for purposes of determining load credits for Seasonal Capacity Performance Resources that are carved out of the capacity market. Thus, a Seasonal Capacity Performance Resource with an Actionable Subsidy could elect the RCO option only if it is commercially aggregated with a Summer Period Capacity Performance Resource or a Winter Period Capacity Performance Resource, as applicable. Absent being commercially aggregated with a matching Seasonal Capacity Performance Reosurce, such resource with an Actionable Subsidy would not be eligible for the RCO option and be subject to the MOPR.

In order to elect the RCO option, a Capacity Market Seller of a Capacity Resource with Actionable Subsidy acknowledges that it agrees to forego all market revenues from PJM's capacity market. This affirmative act of election and, thus, acknowledgment by the resource owner will ensure that it makes informed decisions about the effect of being carved out from the capacity market. Administratively, PJM proposes that the Capacity Market Seller of an eligible Capacity Resource with Actionable Subsidy elect the RCO option by checking a box in "Capacity Exchange" (formerly known as eRPM, or any

Actionable Subsidy. At that point, the resource will be permitted to participate in PJM's capacity market, subject to the MOPR rules described above. Upon returning to PJM's capacity market, a Capacity Resource that is subsequently entitled to another Material Subsidy may again elect the RCO option. While stakeholders discussed whether it would be appropriate to impose a limit on the number of times a Capacity Resource can elect the RCO and then come back in to PJM's capacity market, PJM proposes not to impose a limit. This is because the MOPR rules, as described above, including the requirement that project investment incurred while a resource is carved out will be included in the returning resource's MOPR Floor Offer Price upon re-entry, will sufficiently guard against misuse of this feature. Nevertheless, PJM will monitor whether this feature is problematic and will address it in a future filing, if necessary.

Finally, Capacity Market Sellers may only elect the Resource Carved-Out option for a Delivery Year in advance of the Base Residual Auction for that Delivery Year. Stated another way, a Capacity Resource cannot be carved out for a Delivery Year *after* the BRA for that year has taken place, and Carved Out Resources will not be considered in clearing Incremental Auctions. The reason for this is simple. PJM already secured all the capacity the region needs in the BRA for that Delivery Year, and therefore, it would be unreasonable to allow a Capacity Market Seller to decide on its own to commit more capacity which, effectively would be the result if it carved out. Further, if the resource is existing, then that resource must have offered into the BRA and failed to clear, and the region does not need capacity from that resource for that Delivery Year.

constrained LDA and with the identification of which and how much load should be removed from the auction.[109]

Mr. Keech testifies that removing an amount of load that is equal to the unforced capacity capability of the Carved-Out Resource "would have significant impacts on the implementation and outcomes of the Base Residual Auction," as it requires the subsidized resource and removed load to be co-located.[110] The problem is that this would fail to recognize that some subsidies, like RECs, can be provided across state lines. Mr. Keech further states that if the load and resource are not located in the same LDA, then the CETL for each impacted LDA would need to be discounted.[111] Otherwise, PJM would not be able to "guarantee that the sum of the CETL used by the Resource Carve-Out option plus that used in the market clearing adheres to the limit."[112]

5. RCO Load Offset

A logical consequence that results in removing a subsidized resource from the PJM capacity market, as proposed by the RCO, is that the Carved-Out Resource (while counted as capacity) is not paid by the PJM market for its capacity. The June 29 Order anticipates the subsidizing state will compensate the resource by proposing a mechanism to charge load in the state for the capacity value the subsidized resource brings to PJM. Note, for purposes of *clearing* the market, PJM proposes to allocate the capacity value of the RCO resource as a pro-rata credit across all load in the state on the basis of load's

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109 *See* Keech Aff. ¶¶ 12-16.

110 Keech Aff. ¶ 13.

111 Keech Aff. ¶ 10.

112 Keech Aff. ¶ 16.

proportional share of the state's Daily Unforced Capacity Obligation.[113] This would not preclude, however, a state (or generator) from proposing (for Commission acceptance) other arrangements it might prefer to *charge* load for the capacity credit PJM has applied. In other words the financial *settlement* (which begins in the Delivery Year, three years after the auction has cleared) can assess charges and remit revenues according to the auction clearing rules (a pro-rata credit across all load in the state) or impose the rate on load in different manner as may be proposed by the state. The actual mechanics of this settlement can be facilitated by PJM Settlement as a billing agent, should the state so wish.

But what should not be lost behind these logistics is that the transaction by which the RCO resource charges load to recoup its capacity value is a wholesale transaction, jurisdictional under the FPA. That rate compensates for the sale of a Commission regulated product, namely capacity, as the product is defined in PJM's filed rates. The Commission is therefore bound to ensure this rate is just and reasonable and not unduly discriminatory or preferential as required by the FPA.

It is well established that a federal administrative agency, such as the Commission, cannot delegate its statutory authority to third parties, including state governmental entities, unless Congress has affirmatively permitted such delegation.[114] While there are areas where comity and cooperative federalism warrant recognition of shared jurisdictional responsibility as between the Commission and states, it is hard to

113 *See* pro forma Tariff, Attachment DD, section 5.14(e).

114 *U.S. Telecom Ass'n v. FCC*, 359 F.3d 554 (D.C. Cir. 2004).

the Commission must be satisfied that this rate meets the standards prescribed by the FPA.[118] It may be able to discharge its statutory responsibility by accepting these transactions under the market-based rate authority that the RCO resource may have if the applicants can justify their market-based rate treatment applying to Carved Out Resources which are no longer participating in the competitive market.[119] But any such review needs to be addressed by the Commission so that clarity is provided up front and cleared auction results not later disputed. Alternatively, it may be necessary for the rate to be explicitly filed with the Commission for approval. State Carved Out Resources and associated load would benefit from the Commission speaking to this question and providing guidance in an upcoming order in this docket.

Accordingly, PJM proposes a default rule that, for each Capacity Resource that has elected the RCO option, all LSEs located in the same state as that resource will have their Locational Reliability Charge reduced by a Resource Carve-Out offset.[120] The size of an LSE's offset will be determined based on the ratio of the LSE's Daily Unforced Capacity Obligation in the state and the aggregate total of the Daily Unforced Capacity

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Commission can accept a state proposed rate to charge for Resource Carve-Out capacity that differs from the clearing price charged to other load in PJM arising from PJM's capacity market auctions.

118 This requirement of course goes beyond the level of the rate. During the stakeholder process following the June 29 Order, competitive retail service providers quite correctly emphasized to PJM that the state allocation of capacity charges associated with a Carved Out Resource must also be fair and not unduly discriminatory.

119 This approach would in many cases need to account for the affiliate and affiliate waiver questions raised in *EPSA v. AEP*, Docket No. EL16-33-000, and *EPSA v. FirstEnergy*, Docket No. EL16-34-000.

120 *See* pro forma Tariff, Attachment DD, section 5.14(a).

However, as discussed above, this is merely the default approach to removing from load the capacity cost of a carved out resource. The proposed Tariff contemplates parties seeking alternative approaches to allocate the credit for specific resources through a proceeding under FPA sections 205 or 206[125] To the extent, the Commission accepts such an alternative approach, PJM will implement such approach.

6. RCO Performance Requirement

While a Capacity Resource with Actionable Subsidy may elect to be carved out of PJM's capacity market, it will be treated as if it has a capacity commitment and will be expected to perform as a Capacity Resource in PJM's markets. Thus, the same Capacity Performance obligations will apply to resources that elect the RCO option. Requiring consistent Capacity Performance requirements for all Capacity Resources, including those that elect the RCO option, is critical to maintaining grid reliability. This is because Capacity Resources that elect the RCO option will continue to be included in PJM's the total installed capacity as such resources will continue to participate in the energy and ancillary services market. Thus, Capacity Resources that elect the RCO option should be subject to the same Non-Performance Charges as all other Capacity Resources. Conversely, Capacity Resources that elect the RCO option should be eligible for bonus performance payments in the event such resource provides energy or load reductions above expected levels during a Performance Assessment Interval.

Capacity Resources are carved out under the RCO option will have the ability to cure deficiencies and avoid or reduce associated charges prior to the relevant Delivery Year by procuring replacement capacity. Specifically, a Capacity Resource that is carved

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125 Pro forma Tariff, Attachment DD, section 5.14(e)(ii)(B).

out of the capacity market under the RCO option may procure uncommitted replacement capacity through bilateral transactions and commit such replacement capacity in place of the Carved Out Resource. This will provide resources that are carved out the market with the opportunity to replace capacity as needed. The ability for such resources to procure replacement capacity will allow the resource owners to avoid or reduce Capacity Performance charges in the event of a Performance Assessment Interval. At the same time, replacing such capacity will help to ensure sufficient capacity for grid reliability purposes. Further, requiring resources that are carved out under the RCO option to procure replacement capacity only through bilateral arrangements outside of PJM's Incremental Auction is just and reasonable because those resources have elected to not participate through PJM's capacity market and should not be able to rely on the capacity market in the event replacement capacity is needed.

E. Extended RCO

As noted in the Overview to this submittal, the terms and conditions PJM proposes for the Resource Carve-Out will not fully protect capacity clearing prices from the effects of awarding capacity commitments to uneconomic resources. While PJM's proposed RCO terms and conditions should provide *sufficient* protection that the Commission could find those terms will preserve just and reasonable outcomes, PJM understands that the Commission, in its discretion, could find in this section 206 proceeding that more is needed. To that end, PJM has developed the Extended RCO option for the Commission's consideration. Extended RCO is designed to preserve competitive clearing prices notwithstanding RCO's assignment of capacity commitments to resources whose owners are required by MOPR to submit a competitive offer price, but instead elect the Resource Carve-Out.

Allowing part of the identified demand for capacity to be met by uneconomic offers will, as a matter of basic economics, suppress the clearing price below the level that would result if all offers were economic. As Dr. Hung-Po Chao, PJM's Senior Director, Economics, explains in the accompanying affidavit, "the economic effects of the Resource Carve-Out generally should be expected to be the same as those that would result from the subsidized resource submitting an offer at zero price [given that] [i]f a subsidized (state-sponsored) resource is allowed to satisfy a fixed quantity of demand carved out of the capacity auction, it would have the same economic effects (price suppression and resource substitution) on the capacity market as a zero-price offer in the capacity market."[126] The region's (or constrained area's) demand for resource adequacy is the same, whether the resource is in the auction or not, because there is no load that can be considered individual-resource-specific from a reliability or operational perspective.[127] If uneconomic resources are permitted to satisfy part of the same underlying demand for resource adequacy that the auction seeks to satisfy by procuring economic resources, then uneconomic resources will, by definition, displace some economic resources, and price suppression concerns will therefore arise.

1. Basic Elements of the Extended RCO Proposal

In that scenario, i.e., displacement of economic resources by uneconomic resources suppresses price to a degree deemed unjust and unreasonable, a means is required to restore competitive pricing for the cleared resources that submitted economic

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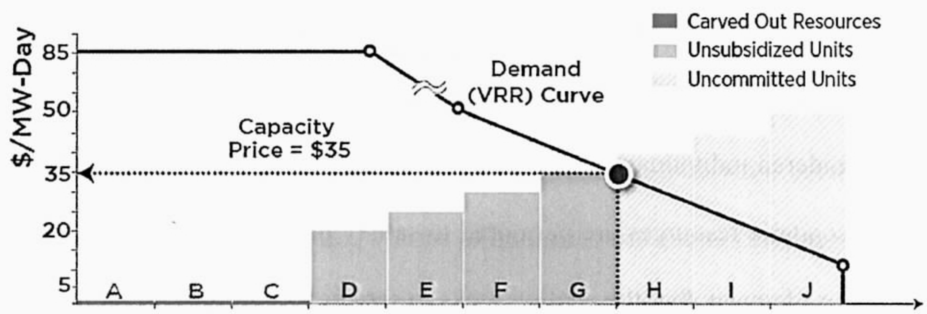
126 Chao Aff. ¶ 9.

127 The Fixed Resource Requirement, by contrast, is available only for the entirety of loads in identified FRR Service Areas bound by appropriate metering, with a long-term commitment by the LSE (i.e., the FRR Entity) to meet the resource adequacy needs of that load. Pro forma RAA, Schedule 8.1.

offers. Extended RCO provides that mechanism, and does so in a way that addresses the two primary concerns in the June 29 Order with competitive price adjustments in such circumstances.[128]

Under the RCO proposal detailed above (with or without Extended RCO), PJM will clear the Base Residual Auction, and assign capacity commitments, based on competitive offers from non-RCO resources and (deemed) zero-price offers from resources that elected RCO.[129] The graph below depicts a simple illustration of the first stage where the Carved Out Resources are included in the supply stack with a Sell Offer of $0.



Extended RCO adds a second stage to the auction to determine a competitive price. In stage two, PJM will remove from the supply stack all resources that elected the RCO option; PJM will make no adjustment to demand (load) or the VRR curve. PJM will then re-run the optimization algorithm and the intersection point between the supply stack and the VRR curve will be the Resource Clearing Price.[130] In this way, BRA

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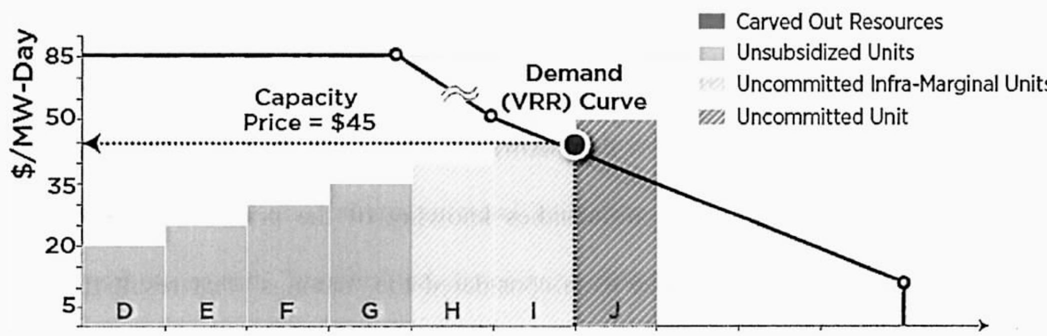
128 *See* pro forma Tariff, Attachment DD, section 5.14(a).

129 Aside from deeming Carved Out Resources to have a zero offer price, PJM is not proposing any changes to the process for how it clears Capacity Resources or the optimization algorithm it employs to clear the Base Residual Auction and assign capacity commitments.

130 *See* pro forma Tariff, Attachment DD, section 5.14(a).

clearing prices would be determined solely on the basis of submitted, competitive offers,[131] and the Resource Clearing Price would be restored to a competitive level, rather than the suppressed price that resulted from applying RCO alone.

To continue the example from above, Carved Out Resources A, B, and C are removed from the supply stack and the remaining supply stack shifts to the left in the second stage of the auction. The remaining supply results in a new intersection that represents the competitive Resource Clearing Price. At this price, the uncommitted infra-marginal units H and I's Sell Offers in the example below are below the competitive Resource Clearing Price, and thus would be infra-marginal at this Resource Clearing Price.



Extended RCO thus does not require insertion of administratively determined competitive prices in the second auction stage. The competitive offers submitted by sellers that have not elected RCO will determine the clearing price. No load is removed, because removing both the RCO resources and associated load would (as explained

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131 The expanded MOPR ensures that all seller-submitted offers are competitive.

above and in Dr. Chao's affidavit) be essentially the same as allowing uneconomic zero-priced offers to displace competitive offers.[132]

2. Extended RCO Resolves the Shortcomings Identified in the June 29 Order with the Prior Attempt to Preserve Competitive Pricing Despite Awarding Capacity to Uneconomic Resources

If the Commission finds Extended RCO warranted, it would counteract two adverse effects of allowing uncompetitive resources to influence clearing prices. First, as recognized in both the economic literature cited by Dr. Chao[133] and the Commission and court precedent cited in the June 29 Order,[134] where a competitive market is used to procure capacity, such market requires competitive pricing to attract unsubsidized resources and ensure ongoing satisfaction of resource adequacy needs. Second, restoring competitive pricing removes (or at least blunts) the incentives of large market buyers (or subsidizing states) to use uncompetitive resources to reduce clearing prices for their auction purchases below competitive levels.[135] This concern is not speculative. States have approved resource subsidies knowing of the price suppressive impacts of such subsidies and may have even considered the "savings" that result from keeping prices artificially low as an offset to paying the subsidies for the resource.[136] For example,

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132 Of course, to the extent the removal of load affects the shape of the VRR curve and shifts it to the left, removing load could even further suppress prices. *See, e.g.*, the PJM IMM's presentation to the September 11, 2018 Markets and Reliability Committee meeting during the PJM stakeholder process on this issue, "Capacity auction Clearing with Resource Specific FRR," available at https://www.pjm.com/-/media/committees-groups/committees/mrc/20180911-special/20180911-imm-sensitivity-analysis.ashx.

133 *See* Chao Aff. ¶ 8.

134 *See* June 29 Order at P 17 n.24.

135 *See* June 29 Order at P 63.

136 May 25 Answer at 7-8 & nn.15-16.

testimony offered to the New Jersey assembly claimed that forestalling threatened retirements of the 3,360 MW Salem and Hope Creek nuclear plants would cost about $300 million in subsidy, but "save" New Jersey $400 million in wholesale power expenditure.[137] To remove this incentive and preserve the long-term resource adequacy benefits of competitive pricing, Extended RCO would set clearing prices based only on competitive offers of economic resources that do not elect the RCO option.

The June 29 Order cited two primary flaws in PJM's Capacity Repricing proposal, which also confronted the challenge of preserving a competitive price

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137 *See, e.g.*, *Committee Meeting*, Senate Environment and Energy Committee and Assembly Telecommunications and Utilities Committee, Transcript at 55 (Dec. 20, 2017), http://www.njleg.state.nj.us/legislativepub/pubhear/senatu12202017.pdf ("NJ Joint Session Meeting") (Dr. Dean Murphy, Principal of The Brattle Group, testifying: "That $280 million or $300 million number is smaller than the $400 million price effect. And that says that when you take both of those things into account . . . electricity costs for consumers, with the [subsidy] program, will actually be lower than they would be if the nuclear plants were to shut and the electricity prices would rise. So there's not actually a cost to consumers; consumers don't pay more to keep these nuclear plants around than if you did not support the plants. They actually pay less, because what they pay to keep the plants around is smaller than the price benefit that keeps them around."); *see also* Dean Murphy & Mark Berkman, *Impacts of Announced Nuclear Retirements in Ohio and Pennsylvania*, The Brattle Group (Apr. 2018), http://files.brattle.com/files/13725 _nuclear_closure_impacts_-_oh_pa_-_apr2018.pdf; Lawrence Makovich & Benjamin Levitt, *Ensuring Resilient and Efficient PJM Electricity Supply*, IHS Markit (Apr. 2018), https://d3n8a8pro7vhmx.cloudfront.net/nuclearmatters /pages/320/attachments/original/1525300979/Ensuring_resilient_and_efficient_PJM_electricity_supply_The_value_of_cost-effective_nuclear_resources_in_the_PJM_power_supply_portfolio.pdf?1525300979; NJ Joint Session Meeting, Transcript at 34 (Dr. Ralph Izzo, CEO, Public Service Enterprise Group testifying that: "So if the cap is what is paid . . . rates would go up, on the aggregate, by $280 million. If we do not take this action, rates will go up by $400 million. So it is far cheaper to keep [Salem and Hope Creek] than not.").

notwithstanding accommodation of state-subsidized uneconomic resources. Extended RCO reasonably resolves both of those concerns.[138]

a. Extended RCO Ensures Subsidized Resources do not Receive a Windfall

First, the June 29 Order found that paying subsidized resources the same adjusted clearing price as non-subsidized offers provides the subsidized resources a "windfall"[139] and unduly discriminates against non-subsidized resources.[140] Extended RCO, by contrast, provides no such windfall and establishes no such discrimination, because subsidized uneconomic resources are "carved out" and receive no compensation from the capacity auction. Extended RCO thus honors the Commission's guidance that the "receipt of out-of-market support is a difference that requires different ratemaking treatment when such support has a material effect on price."[141] Resources electing RCO are subject to the "different ratemaking treatment" of the out-of-market compensation established by the state or load serving entity (as applicable) and separately approved by the Commission under FPA section 205.

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138 Importantly, the June 29 Order "confine[d its] finding . . . to PJM's Capacity Repricing proposal, as submitted, *as a stand alone solution* to address the impact of resources receiving out-of-market support." June 29 Order at P 65 (emphasis added). The June 29 Order, therefore, is without prejudice to proposals, like Extended RCO, that works to complement the Commission's preferred solution of a Resource Carve-out; that differs from Capacity Repricing; and that acknowledges and resolves the main concerns the June 29 Order raised with Capacity Repricing.

139 June 29 Order at P 67.

140 June 29 Order at P 68; *see also id.* at P 66 ("We find it unjust and unreasonable, and unduly discriminatory or preferential, 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.").

141 June 29 Order at P 68.

b. <u>Extended RCO Ensures a Reasonable Connection Between Clearing Prices and Resource Compensation</u>

Second, the June 29 Order found that "by setting a clearing price that is disconnected from the price used to determine which resources receive capacity commitments, the market clearing price under Capacity Repricing will send incorrect signals, leading to greater uncertainty with respect to entry and exit decisions."[142] Extended RCO directly addresses this clearing-price signaling concern by recognizing and compensating the price formation benefit provided by economic resources whose offers determine the competitive clearing price. All non-RCO resources that commit capacity in the BRA receive that clearing price. In addition, non-RCO resources that submit infra-marginal offers, *but do not clear* because they are "crowded out" by the capacity commitment awarded to RCO resources, will be paid the difference between their offer and the clearing price. That difference is the same infra-marginal rent that any competitive seller receives by offering an efficient resource with costs below the clearing price.

As Dr. Chao explains, this payment is grounded in the fundamental economic principles that have governed the RPM auctions since their inception and it preserves the correct price signals and incentives.[143] Extended RCO therefore removes the "disconnect" (highlighted by the June 29 Order) between clearing prices and economic resource compensation.

Elaborating on these points, each resource that clears RPM's single clearing price auctions receives compensation that conceptually has two parts: i) the resource's

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142 *Id.* at P 64.

143 Chao Aff. ¶¶ 16-17.

avoidable costs of providing capacity in that Delivery Year, and ii) infra-marginal rents, i.e., the part of the clearing price that is above a rational seller's marginal cost-based offer. RPM incents the seller to minimize its costs so as to maximize its infra-marginal rents. This single-clearing price approach with its awarding infra-marginal rents promotes resource efficiency, forces the seller to take the risk of covering its costs, and provides the market surplus needed to help finance future investments and induce competitive market entry and exit.[144]

As Dr. Chao explains, accommodating state subsidies may help states pursue their policy objectives that are not valued in the market, but that resource subsidization also imposes costs on society.[145] In economic terms, that cost is known as "dead-weight loss," i.e., the reduction in market surplus, which includes the sum of the infra-marginal rents earned by economic resources in the market.[146] Resource Carve-Out, *without Extended RCO*, presents a classic example of such dead-weight loss, because the market substitutes each subsidized *uneconomic* resource in place of an equivalent amount of *economic* resources. The Resource Carve-Out proposal also provides a precise map of the amount of that dead-weight loss, and which market participants bear that cost: every seller that offers a resource at a price below the clearing price *that does not clear*, bears the cost of accommodating the state-sponsored resource, and the amount of the cost is the infra-marginal rent it was denied precisely because it was crowded out by the uneconomic subsidized resources.[147]

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144 Chao Aff. ¶ 15.

145 Chao Aff. ¶¶ 5-6, 8.

146 Chao Aff. ¶ 14.

147 Chao Affidavit at ¶¶ 14-16.

Extended RCO therefore pays that displaced infra-marginal resource the infra-marginal rents it would have received had it not been forced out to make room for the uneconomic resource.[148] The displaced seller does not receive compensation for the amount of its offer, because that part reflects the avoidable costs that it need not incur, because it is not committed as capacity. As Dr. Chao shows, the result is comparable to a seller with a cleared infra-marginal offer that pays a second seller to take on its position, at a price equal to the first seller's avoidable costs.[149] The first seller is then relieved of its capacity commitment, but has retained the infra-marginal rent, i.e., the difference between its original avoidable cost offer and the clearing price.

Critically, this approach preserves and properly aligns the price signals and incentives for economic resources. Under PJM's Capacity Repricing proposal, the displaced infra-marginal resource would get nothing if it failed to clear the first stage of the auction. That seller was therefore incented to offer as low as possible, in order to clear the *first* stage, where it had to compete against the uneconomic subsidized offer. That displaced seller embodied the "disconnect" between clearing prices and capacity commitments decried by the June 29 Order: its offer was low enough to earn it a capacity award based on the second-stage clearing price paid to all other economic offers, but it lost out, because capacity commitments were determined in the first stage with lower (subsidy-influenced) prices.

Extended RCO, by contrast, restores every non-RCO seller's incentive to submit an economic offer at its avoidable costs. So long as its offer is infra-marginal, it will earn

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148 Chao Affidavit at ¶ 16.

149 Chao Affidavit at ¶ 16.

infra-marginal rents, even if it loses out on a capacity commitment because it is displaced by a subsidized resource. RPM's ability to send price signals based on the marginal costs of providing capacity at particular locations in the PJM Region is therefore preserved.[150]

Extended RCO also sends an important additional signal to the subset of resources that fail to secure a capacity commitment, but are awarded infra-marginal rents—it's time to consider retirement. By definition, the resources in that category are the highest-cost infra-marginal resources. They may be older, less efficient resources that are marginally economic for the current Delivery Year, but are at risk of becoming uneconomic as newer, more efficient, lower-cost resources continue to come on line.

3. Extended RCO Reasonably Assigns "Deadweight-Loss" Costs to the Resources that Choose to Submit Uneconomic offers

Infra-marginal sellers awarded capacity commitments receive capacity payments that are recovered from Load Serving Entities. [Extended RCO will also pay infra-marginal resources that *do not* clear for the infra-marginal rents they would have received had they not been displaced to make room for the subsidized uneconomic resource that elected the Resource Carve-Out. As explained by Dr. Chao, those payments are reasonably recovered from those uneconomic RCO resources.[151]

Making room for that uneconomic resource is the action that gives rise to the deadweight loss: an economic resource is squeezed out, and replaced with an uneconomic resource. The economic resource was infra-marginal, and would have received infra-marginal rents (i.e., the difference between its offer and the clearing price) had it not been displaced.

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150 Chao Aff. ¶ 17.

151 Chao Aff. ¶¶ 18-19.

More specifically, the action that gives rise to that loss of efficient market surplus *is the choice by the seller of the subsidized* resource to elect the Resource Carve-Out. That seller is the participant in PJM's capacity market, it owns the economic resource, and it chooses whether, and at what price, it wishes to offer that resource into the capacity market. While a state may provide the subsidy that enables the seller to offer an uneconomic resource into RPM at a subsidized price, the seller is an autonomous economic actor and ultimately chooses how to profit from or dispose of its resource. Indeed, under controlling legal principles, a state would be *preempted* by federal law from conditioning payment of a resource subsidy on the resource owner's agreement to offer the resource into the wholesale market at an uneconomic price that is guaranteed to clear.[152] The dead-weight loss resulting from the seller's uneconomic offer, as reflected in the infra-marginal rents paid to "crowded-out" infra-marginal sellers, is caused by, and appropriately recovered from, the seller that chooses to commit an uneconomic resource using the Resource Carve-Out option.

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[152] *See Hughes v. Talen Energy Marketing Mktg, LLC*, 136 S. Ct. 1288, 1298 (2016) ("States may not seek to achieve ends, however legitimate, through regulatory means that intrude on FERC's authority over interstate wholesale rates . . . ."); *see also Elec. Power Supply Ass'n v. Star*, Nos. 17-2433 & 17-2445, 2018 U.S. App. LEXIS 25980, at *16-17 (7th Cir. Sept. 13, 2018) (upholding Illinois Zero Emission Credit program,); *Coalition for Competitive Elec. v. Zibelman*, No. 17-2654-cv, 2018 U.S. App. LEXIS 27605 (2d Cir. Sept. 27, 2018) (upholding New York Zero Emission Credit program).

III. CONCLUSION

For the foregoing reasons, the Commission should find the proposal herein as a just and reasonable replacement rate and order a compliance filing to revise the Tariff, RAA and Operating Agreement as proposed in this filing.

Respectfully submitted,

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October 2, 2018

Attachment A

TARIFF, SECTION 1 – NEW DEFINTIONS
PRO FORMA CHANGES

Capacity Resource with Actionable Subsidy:

"Capacity Resource with Actionable Subsidy" or "Capacity Resources with Actionable Subsidies" shall have the meaning provided in Tariff, Attachment DD, section 5.14(j).

Carved Out Resource:

"Carved Out Resource" shall mean a Capacity Resource that is the subject of a Resource Carve-Out.

Infra-Marginal Rent Payment:

"Infra-Marginal Rent Payment" shall mean a payment made to a Capacity Resource that submitted a Sell Offer that cleared in the re-run of the optimization algorithm, but had not cleared in the original optimization algorithm. The Infra-Marginal Rent Payment shall be equal to the difference between the Capacity Resource Clearing Price and such Capacity Resources' Sell Offer price multiplied by the MW quantity of such Sell Offer that cleared in the re-run of the optimization algorithm."

Material Subsidy:

"Material Subsidy" shall mean: (1) material payments, concessions, rebates, or subsidies as a result of any state governmental action connected to the procurement of electricity or other attribute from an existing Capacity Resource, or the construction, development, or operation, (including but not limited to support which has the effect of allowing the unit to clear in any RPM Auction) of a Capacity Resource, or (2) other material support or payments obtained in any state-sponsored or state-mandated processes, connected to the procurement of electricity or other attribute from an existing Capacity Resource, or the construction, development, or operation, (including but not limited to support which has the effect of allowing the unit to clear in any RPM Auction), of the Capacity Resource, or (3) material payments, concessions, rebates, or subsidies authorized pursuant to federal legislation or a federal subsidy program enacted after March 21, 2016 connected to the construction, development, or operation, (including but not limited to support which has the effect of allowing the unit to clear in any RPM Auction) of the Capacity Resource unless such federal legislation specifically exempts the application of MOPR to the program being authorized pursuant to federal legislation, or (4) other material support or payments obtained in any federally-sponsored or federally-mandated processes enacted after March 21, 2016, connected to the construction, development, or operation, (including but not limited to support which has the effect of allowing the unit to clear in any RPM Auction), of the Capacity Resource, unless such federal legislation specifically exempts the application of MOPR to the program being authorized pursuant to federal legislation, provided that any subsidy under (1) through (4) is 1% or more of the resource's actual or anticipated total revenues from PJM's energy, capacity, and ancillary services markets. A Material Subsidy shall not include (5) payments (including payments in lieu of taxes), concessions, rebates, subsidies, or incentives designed to incent, or participation in a program, contract or other arrangement that utilizes criteria designed to incent or promote, general industrial development in an area; (6) payments, concessions, rebates, subsidies or incentives from a county or other local governmental authority using eligibility or selection criteria designed to incent, siting facilities in that county or locality rather than another county or locality; or (7) A renewable energy credit (including for onshore and offshore wind, as well as solar, collectively, RECs) will not be considered to be a Material Subsidy, if the Capacity Market Seller sells the REC to a purchaser that is not required by a state program to purchase the REC, and that purchaser does not receive any state financial inducement or credit for the purchase of the REC.

Resource Carve-Out:

"Resource Carve-Out" shall mean a Capacity Resource that meets the requirements set forth in Tariff, Attachment DD, section 5.14(h)(vi).

TARIFF, ATTACHMENT K-APPENDIX, SECTION 1.10.1A
OPERATING AGREMENT, SCHEDULE 1, SECTION 1.10.1A
PRO FORMA CHANGES

(d) Market Sellers wishing to sell into the Day-ahead Energy Market shall submit offers for the supply of energy (including energy from hydropower units), demand reductions, Regulation, Operating Reserves or other services for the following Operating Day. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this Section 1.10.1A(d), Schedule 2 of the Operating Agreement, and the PJM Manuals, as applicable. Market Sellers owning or controlling the output of a Generation Capacity Resource that <u>is the subject of a Carved Out Resource or</u> was committed in an FRR Capacity Plan, self-supplied, offered and cleared in a Base Residual Auction or Incremental Auction, or designated as replacement capacity, as specified in Attachment DD of the PJM Tariff, and that has not been rendered unavailable by a Generator Planned Outage, a Generator Maintenance Outage, or a Generator Forced Outage are subject to a Day-ahead Energy Market must-offer requirement and a Real-time Energy Market must-offer requirement and pursuant thereto shall submit offers for the available capacity of such Generation Capacity Resource, including any portion that is self-scheduled by the Generating Market Buyer. Such offers shall be based on the ICAP equivalent of the Market Seller's cleared UCAP capacity commitment, provided, however, where the underlying resource is a Capacity Storage Resource or an Intermittent Resource, the Market Seller shall satisfy the Day-ahead Energy Market must-offer requirement and the Real-time Energy Market must-offer requirement by either self-scheduling or offering the unit as a dispatchable resource, in accordance with the PJM Manuals, where the hourly self-scheduled values for such Capacity Storage Resources and Intermittent Resources may vary hour to hour from the capacity commitment. Any offer not designated as a Maximum Emergency offer shall be considered available for scheduling and dispatch under both Emergency and non-Emergency conditions. Offers may only be designated as Maximum Emergency offers to the extent that the Generation Capacity Resource falls into at least one of the following categories:

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TARIFF, ATTACHMENT M – APPENDIX, SECTION II
PRO FORMA CHANGES

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D. Unit Specific Minimum Sell Offers:

1. If a Capacity Market Seller timely submits a~~an exception~~ request for a resource-specific MOPR Floor Offer Price determination or a Self-Supply Exemption, with all of the required documentation as specified in Tariff, Attachment DD, section 5.14(h), the Market Monitoring Unit shall review the request and documentation and shall provide in writing to the Capacity Market Seller and the Office of the Interconnection by no later than ninety (90) days prior to the commencement of the offer period for the RPM Auction whether it believes the request should be granted in accordance with the standards and criteria set forth in Tariff, Attachment DD, section 5.14(h). ~~(90) days prior the commencement of the offer period for the RPM Auction in which it seeks to submit its Sell Offer (a) its determination whether the level of the proposed Sell Offer raises market power concerns, and (b) if so it shall calculate and provide to such Capacity Market Seller a minimum Sell offer Based on the data and documentation received~~.

2. All data and information submitted to the Office of the Interconnection or the Market Monitoring Unit by a Market Participant is subject to verification by the Market Monitoring Unit.

3. In the event that the Market Monitoring Unit reasonably believes that a request for a Self-Supply Exemption that has been granted contains fraudulent or material misrepresentations or omissions such that the Capacity Market Seller would not have been eligible for the exemption from being a Capacity Resource with Actionable Subsidy for that Capacity Resource had the request not contained such misrepresentations or omissions, then it shall notify the Office of the Interconnection and Capacity Market Seller of its findings and provide the Office of the Interconnection with all of the data and documentation supporting its findings, and may take any other action required or permitted under Attachment M.

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TARIFF, ATTACHMENT DD
PRO FORMA CHANGES

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5.11 Posting of Information Relevant to the RPM Auctions

a) In accordance with the schedule provided in the PJM Manuals, PJM will post the following information for a Delivery Year prior to conducting the Base Residual Auction for such Delivery Year:

i) The Preliminary PJM Region Peak Load Forecast (for the PJM Region, and allocated to each Zone);

ii) The PJM Region Installed Reserve Margin, the Pool-wide average EFORd, the Forecast Pool Requirement, and all applicable Capacity Import Limits;

iii) For the Delivery Years through May 31, 2018, the Demand Resource Factor;

iv) The PJM Region Reliability Requirement, and the Variable Resource Requirement Curve for the PJM Region, including the details of any adjustments to account for Price Responsive Demand and any associated PRD Reservation Prices;

v) The Locational Deliverability Area Reliability Requirement and the Variable Resource Requirement Curve for each Locational Deliverability Area for which a separate Variable Resource Requirement Curve has been established for such Base Residual Auction, including the details of any adjustments to account for Price Responsive Demand and any associated PRD Reservation Prices, and the CETO and CETL values for all Locational Deliverability Areas;

vi) For the Delivery Years starting June 1, 2014 and ending May 31, 2017, the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement for the PJM Region and for each Locational Deliverability Area for which PJM is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year; and for the 2017/2018 Delivery Year , the Limited Resource Constraints and the Sub-Annual Resource Constraints for the PJM Region and for each Locational Deliverability Area for which PJM is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year. For the 2018/2019 and 2019/2020 Delivery Years, the Office of the Interconnection shall establish the Base Capacity Demand Resource Constraints and the Base Capacity Resource Constraints for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year;

vii) Any Transmission Upgrades that are expected to be in service for such Delivery Year, provided that a Transmission Upgrade that is Backbone Transmission satisfies the project development milestones set forth in section 5.11A;

viii) The bidding window time schedule for each auction to be conducted for such Delivery Year; ~~and~~

ix) The Net Energy and Ancillary Services Revenue Offset values for the PJM Region for use in the Variable Resource Requirement Curves for the PJM Region and each Locational Deliverability Area for which a separate Variable Resource Requirement Curve has been established for such Base Residual Auction; and~~.~~

x) At least twenty (20) days prior to conducting the Base Residual Auction for such Delivery Year, the aggregate megawatt quantity of all Carved Out Resources.

b) The information listed in (a) will be posted and applicable for the First, Second, Third, and Conditional Incremental Auctions for such Delivery Year, except to the extent updated or adjusted as required by other provisions of this Tariff.

c) In accordance with the schedule provided in the PJM Manuals, PJM will post the Final PJM Region Peak Load Forecast and the allocation to each zone of the obligation resulting from such final forecast, following the completion of the final Incremental Auction (including any Conditional Incremental Auction) conducted for such Delivery Year;

d) In accordance with the schedule provided in the PJM Manuals, PJM will advise owners of Generation Capacity Resources of the updated EFORd values for such Generation Capacity Resources prior to the conduct of the Third Incremental Auction for such Delivery Year.

e) After conducting the Reliability Pricing Model Auctions, PJM will post the results of each auction as soon thereafter as possible, including any adjustments to PJM Region or LDA Reliability Requirements to reflect Price Responsive Demand with a PRD Reservation Price equal to or less than the applicable Base Residual Auction clearing price. The posted results shall include graphical supply curves that are (a) provided for the entire PJM Region, (b) provided for any Locational Deliverability Area for which there are four (4) or more suppliers, and (c) developed using a formulaic approach to smooth the curves using a statistical technique that fits a smooth curve to the underlying supply curve data while ensuring that the point of intersection between supply and demand curves is at the market clearing price.

If PJM discovers an error in the initial posting of auction results for a particular Reliability Pricing Model Auction, it shall notify Market Participants of the error as soon as possible after it is found, but in no event later than 5:00 p.m. of the fifth Business Day following the initial publication of the results of the auction. After this initial notification, if PJM determines it is necessary to post modified results, it shall provide notification of its intent to do so, together with all available supporting documentation, by no later than 5:00 p.m. of the seventh Business Day following the initial publication of the results of the auction. Thereafter, PJM must post on its Web site any corrected auction results by no later than 5:00 p.m. of the tenth Business Day following the initial publication of the results of the auction. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced auction results are under publicly noticed review by the FERC.

TARIFF, ATTACHMENT DD
PRO FORMA CHANGES

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5.14 Clearing Prices and Charges

a) Capacity Resource Clearing Prices

For each Base Residual Auction and Incremental Auction, the Office of the Interconnection shall calculate a clearing price to be paid for each megawatt-day of Unforced Capacity that clears in such auction. The Capacity Resource Clearing Price for each LDA will be the marginal value of system capacity for the PJM Region, without considering locational constraints, adjusted as necessary by any applicable Locational Price Adders, Annual Resource Price Adders, Extended Summer Resource Price Adders, Limited Resource Price Decrements, Sub-Annual Resource Price Decrements, Base Capacity Demand Resource Price Decrements, and Base Capacity Resource Price Decrements, all as determined by the Office of the Interconnection based on the optimization algorithm, where after the optimization algorithm determines the lowest-cost overall clearing result that satisfies all applicable constraints and requirements, in accordance with Attachment, DD, section 5.12, to determine the Capacity Resource Clearing Prices for each LDA, the Office of the Interconnection shall re-run the optimization algorithm using the same submitted Sell Offers, except that all Sell Offers for Carved Out Resources shall not be considered. The Capacity Resource Clearing Price shall be paid to each Capacity Resource that submitted a Sell Offer that cleared in both the original optimization algorithm and the re-run of the optimization algorithm. An Infra-Marginal Rent Payment shall be paid to each Capacity Resource that submitted a Sell Offer that cleared in the re-run of the optimization algorithm, but had not cleared in the original optimization algorithm. Such Infra-Marginal Rent Payment shall be equal to the difference between the Capacity Resource Clearing Price and such Capacity Resources' Sell Offer price multiplied by the MW quantity of such Sell Offer that cleared in the re-run of the optimization algorithm. If a Capacity Resource is located in more than one Locational Deliverability Area, it shall be paid the highest Locational Price Adder in any applicable LDA in which the Sell Offer for such Capacity Resource cleared. The Annual Resource Price Adder is applicable for Annual Resources only. The Extended Summer Resource Price Adder is applicable for Annual Resources and Extended Summer Demand Resources.

The Locational Price Adder applicable to each cleared Seasonal Capacity Performance Resource is determined during the post-processing of the RPM Auction results consistent with the manner in which the auction clearing algorithm recognizes the contribution of Seasonal Capacity Performance Resource Sell Offers in satisfying an LDA's reliability requirement. For each LDA with a positive Locational Price Adder with respect to the immediate higher level LDA, starting with the lowest level constrained LDAs and moving up, PJM determines the quantity of equally matched Summer-Period Capacity Performance Resources and Winter-Period Capacity Performance Resources located and cleared within that LDA. Up to this quantity, the cleared Summer-Period Capacity Performance Resources and Winter-Period Capacity Performance Resources with the lowest Sell Offer prices will be compensated using the highest Locational

Price Adder applicable to such LDA; and any remaining Seasonal Capacity Performance Resources cleared within the LDA are effectively moved to the next higher level constrained LDA, where they are considered in a similar manner for compensation.

i) The sum of all Infra-Marginal Rent Payments arising from the clearing of a Base Residual Auction shall be allocated pro rata, based on the megawatts of such capacity commitments, among and charged to the Capacity Market Sellers that elected the Resource Carve-Out as to Capacity Resources committed in the original optimization algorithm of such Base Residual Auction.

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e) Locational Reliability Charge

(i) In accordance with the Reliability Assurance Agreement, each LSE shall incur a Locational Reliability Charge (subject to certain offsets and other adjustments as described in sections 5.14B, 5.14C, 5.14D, 5.14E and 5.15) equal to such LSE's Daily Unforced Capacity Obligation in a Zone during such Delivery Year multiplied by the applicable Final Zonal Capacity Price in such Zone, less any applicable Resource Carve-Out offset. PJMSettlement shall be the Counterparty to the LSEs' obligations to pay, and payments of, Locational Reliability Charges.

(ii) Resource Carve-Out Offset

(A) General Rule. For each Carved Out Resource, each LSE that is assessed a Locational Reliability Charge for end-use customers in the same state in which such Carved Out Resource is located shall be entitled to a Resource Carve-Out offset credit against its Locational Reliability Charge, where the Resource Carve-Out offset is equal to the product of: (1) ([the Unforced Capacity of that Carved Out Resource] times [the Resource Clearing Price for the LDA in which the Carved Out Resource is located, for the auction in which the resource cleared]) and (2) [the LSE's Daily Unforced Capacity Obligation in that state] divided by [the sum of the Daily Unforced Capacity Obligations of all the LSEs within that state].

(B) The Commission may accept or approve alternate allocations of the Resource Carve-Out offset for any specific Carved Out Resource as the result of a Federal Power Act section 205 or 206 proceeding.

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h) ~~Minimum Offer Price Rule for Certain Generation Capacity Resources~~Sell Offers for Capacity Resources with Actionable Subsidies ~~-~~

(i) General Rule. Any Sell Offer based on a Capacity Resource with Actionable Subsidy submitted in any RPM Auction conducted shall be subject to the Minimum Offer Price Rule, unless the Capacity Market Seller has elected the Resource Carve-Out option for such resource.

(ii) Capacity Resource with Actionable Subsidy. A Capacity Resource that meets the following criteria shall be deemed to be a Capacity Resource with Actionable Subsidy:

(A) The Capacity Resource has an Unforced Capacity of 20 MW or greater and is a Demand Resource or a Generation Capacity Resource, or uprate or planned uprate, to a Generation Capacity Resource;

(B) The Capacity Market Seller is entitled to a Material Subsidy with regard to such Capacity Resource and the Capacity Market Seller has not certified that it will forego receiving any Material Subsidy for such Capacity Resource during the applicable Delivery Year, or the Capacity Market Seller has received a Material Subsidy with regard to such Capacity Resource and yet to clear any RPM Auction since it received such Material Subsidy;

(C) For a Generation Capacity Resource, electricity production is not the primary purpose of the facility at which the energy is produced, but rather it is a byproduct of the resource's primary purpose; and

(D) The Capacity Market Seller has not obtained a Self-Supply Exemption for such Capacity Resource. A Capacity Market Seller that is a Self-Supply LSE will not be considered as having a Capacity Resource with Actionable Subsidy in any RPM Auction for any Delivery Year, and thus will be treated as having a Self-Supply Exemption, if such Capacity Resource satisfies the criteria specified below:

(1) For purposes of the Self-Supply Exemption:

(a) "Self-Supply LSE" means the following types of Load Serving Entity, which operate under long-standing business models: Public Power Entity, Single Customer Entity, or Vertically Integrated Utility.

(b) "Public Power Entity" means cooperative and municipal utilities, including public power supply entities comprised of either or both of the same and rural electric cooperatives, and joint action agencies.

(c) "Vertically Integrated Utility" means a utility that owns generation, includes such generation in its regulated rates, and earns a regulated return on its investment in such generation.

(d) "Single Customer Entity" means an LSE that serves at retail only customers that are under common control with such LSE, where such control means holding 51% or more of the voting securities or voting interests of the LSE and all its retail customers.

(e) All capacity calculations shall be on an Unforced Capacity basis.

(f) Estimated Capacity Obligation and Owned and Contracted Capacity shall be measured on a three-year average basis for the three years starting with the first day of the Delivery Year associated with the RPM Auction for which the exemption is being sought ("MOPR Exemption Measurement Period"). Such measurements shall be verified by PJM using the latest available data that PJM uses to determine capacity obligations.

(g) The Self-Supply LSE's Estimated Capacity Obligation shall be the average, for the three Delivery Years of the MOPR Exemption Measurement Period, of the Self-Supply LSE's estimated share of the most recent available Zonal Peak Load Forecast for each such Delivery Year for each Zone in which the Self-Supply LSE will serve load during such Delivery Year, times the Forecast Pool Requirement established for the first such Delivery Year, and shall be stated on an Unforced Capacity basis. Notwithstanding the foregoing, solely in the case of any Self-Supply LSE that elects to demonstrate to the Office of the Interconnection that its annual peak load occurs in the winter, such LSE's Estimated Capacity Obligation determined solely for the purposes of this subsection 5.14(h) shall be based on its winter peak. Once submitted, an exemption request shall not be subject to change due to later revisions to the PJM load forecasts for such Delivery Years. The Self-Supply LSE's Estimated Capacity Obligation shall be limited to the LSE's firm obligations to serve specific identifiable customers or groups of customers including native load obligations and specific load obligations in effective contracts for which the term of the contract includes at least a portion of the Delivery Year associated with the RPM Auction for which the exemption is requested (and shall not include load that is speculative or load obligations that are not native load or customer specific); as well as retail loads of entities that directly (as through charges on a retail electric bill) or indirectly, contribute to the cost recovery of the MOPR Screened Generation Resource; provided, however, nothing herein shall require a Self-Supply LSE that is a joint owner of a MOPR Screened Generation Resource to aggregate its expected loads with the loads of any other joint owner for purposes of such Self-Supply LSE's exemption request.

(h) "Owned and Contracted Capacity" includes all of the Self-Supply LSE's qualified Capacity Resources, whether internal or external to PJM. To qualify for a Self-Supply Exemption, the Capacity Resource must be used by the Self-Supply LSE, meaning such Self-Supply LSE is the beneficial off-taker of such generation such that the owned or contracted for Capacity Resource is for the Self-Supply LSE's use to supply its customer(s).

(i) If multiple entities will have an ownership or contractual share in, or are otherwise sponsoring, the Capacity Resource, the positions of each such entity will be measured and considered for a Self-Supply Exemption with respect to the individual Self-Supply LSE's ownership or contractual share of such resource.

(2) Cost and revenue criteria. The costs and revenues associated with a Capacity Resource for which a Self-Supply LSE to be treated as a Self-Supply Exemption may permissibly reflect: (a) payments, concessions, rebates, subsidies, or incentives designed to incent or promote, or participation in a program, contract, or other arrangement that utilizes criteria designed to incent or promote, general industrial development in an area; (b) payments,

concessions, rebates, subsidies or incentives from a county or other local government authority designed to incent, or participation in a program, contract or other arrangement established by a county or other local governmental authority utilizing eligibility or selection criteria designed to incent, siting facilities in that county or locality rather than another county or locality; (c) revenues received by the Self-Supply LSE attributable to the inclusion of costs of the Capacity Resource in such LSE's regulated retail rates where such LSE is a Vertically Integrated Utility and the Capacity Resource is planned consistent with such LSE's most recent integrated resource plan found reasonable by the RERRA to meet the needs of its customers; and (d) payments to the Self-Supply LSE (such as retail rate recovery) traditionally associated with revenues and costs of Public Power Entities (or joint action of multiple Public Power Entities); revenues to a Public Power Entity from its contracts having a term of one year or more with its members or customers (including wholesale power contracts between an electric cooperative and its members); or cost or revenue advantages related to a longstanding business model employed by the Self-Supply LSE, such as its financial condition, tax status, access to capital, or other similar conditions affecting the Self-Supply LSE's costs and revenues. A Self-Supply Exemption shall not be permitted to the extent that the Self-Supply LSE, acting either as the Capacity Market Seller or on behalf of the Capacity Market Seller, has any formal or informal agreements or arrangements to seek, recover, accept or receive: (e) any material payments, concessions, rebates, or subsidies, connected to the construction, or clearing in any RPM Auction, of the Capacity Resource, not described by (a) through (d) of this section; or (f) other support through contracts having a term of one year or more obtained in any procurement process sponsored or mandated by any state legislature or agency connected with the construction, or clearing in any RPM Auction, of the Capacity Resource. Any cost and revenue advantages described by (a) through (d) of this subsection that are material to the cost of the Capacity Resource and that are irregular or anomalous, that do not reflect arms-length transactions, or that are not in the ordinary course of the Self-Supply LSE's business, shall disqualify application of the Self-Supply Exemption unless the Self-Supply LSE demonstrates in the exemption process provided hereunder that such costs and revenues are consistent with the overall objectives of the Self-Supply Exemption.

(3) Owned and Contracted Capacity. To be treated as a Self-Supply Exemption, the Self-Supply LSE, acting either as the Capacity Market Seller or on behalf of the Capacity Market Seller, must demonstrate that any Planned Generation Capacity Resource of such Self-Supply LSE is included in such LSE's Owned and Contracted Capacity and that its Owned and Contracted Capacity meets the criteria outlined below after the addition of such Capacity Resource.

(4) Maximum Net Short Position. If the excess, if any, of the Self-Supply LSE's Estimated Capacity Obligation above its Owned and Contracted Capacity ("Net Short") is less than the amount of Unforced Capacity specified in or calculated under the table below for all relevant areas based on the specified type of LSE, then this exemption criterion is satisfied; however, to the extent this exemption criteria is not satisfied, only the Self-Supply LSE's Capacity Resources that have not cleared in an RPM Auction for any prior Delivery Year do not qualify for a Self-Supply Exemption and may be subject to the Minimum Offer Price Rule, while all of the Self-Supply LSE's Capacity Resources that previously have cleared an RPM Auction for any Delivery Year shall qualify for the Self-Supply Exemption and are not subject to the Minimum Offer Price Rule. For this purpose, the Net Short position shall

be calculated for any Self-Supply LSE requesting this exemption for the PJM Region and for each LDA specified in the table below in which the Capacity Resource is located (including through nesting of LDAs) to the extent the Self-Supply LSE has an Estimated Capacity Obligation in such LDA. If the Self-Supply LSE does not have an Estimated Capacity Obligation in an evaluated LDA, then the Self-Supply LSE is deemed to satisfy the test for that LDA.

Type of Self-Supply LSE	Maximum Net Short Position (UCAP MW, measured at RTO, MAAC, SWMAAC and EMAAC unless otherwise specified)
Single Customer Entity	150 MW
Public Power Entity	1000 MW
Multi-state Public Power Entity*	1000 MW in SWMAAC, EMAAC, or MAAC LDAs and 1800 MW RTO
Vertically Integrated Utility	20% of LSE's Estimated Capacity Obligation

*A Multi-state Public Power Entity shall not have more than 90% of its total load in any one state.

(5) Maximum Net Long Position. This criterion is applicable to the determination of whether a Self-Supply LSE's Sell Offer for a Capacity Resource that has not cleared in an RPM Auction for any prior Delivery Year shall be subject to the Minimum Offer Price Rule; regardless of the outcome of this criterion, all of the Self-Supply LSE's Capacity Resources that previously have cleared an RPM Auction for any Delivery Year shall qualify for the Self-Supply Exemption and are not subject to the Minimum Offer Price Rule. If the excess, if any, of the Self-Supply LSE's Owned and Contracted Capacity for the PJM Region above its Estimated Capacity Obligation for the PJM Region ("Net Long"), is less than the amount of Unforced Capacity specified in or calculated under the table below, then this exemption criterion is satisfied:

Self-Supply LSE Total Estimated Capacity Obligation in the PJM Region (UCAP MW)	Maximum Net Long Position (UCAP MW)
Less than 500	75 MW
Greater than or equal to 500 and less than 5,000	15% of LSE's Estimated Capacity Obligation
Greater than or equal to 5,000 and less than 15,000	750 MW
Greater than or equal to 15,000 and less than 25,000	1,000 MW
Greater than or equal to 25,000	4% of LSE's Estimated Capacity Obligation capped at 1300 MWs

If a Capacity Resource that has not cleared in an RPM Auction for any prior Delivery Year causes the Self-Supply LSE's Net Long Position to exceed the applicable threshold stated above, the MOPR Floor Offer Price shall apply, for the Delivery Year in which such threshold is exceeded, only to the quantity of Unforced Capacity of such resource(s) that exceeds such threshold. In such event, such Unforced Capacity of such resource(s) shall be subject to the MOPR Floor Offer Price for only the RPM Auction in which such threshold is exceeded.

(6) Beginning with the Delivery Year that commences June 1, 2020, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall review the Maximum Net Short and Net Long positions, as required by the foregoing subsections. Such review may include, without limitation, analyses under various appropriate scenarios of the minimum net short quantities at which the benefit to an LSE of a clearing price reduction for its capacity purchases from the RPM Auction outweighs the cost to the LSE of a new or existing generating unit that is offered at an uneconomic price, and may, to the extent appropriate, reasonably balance the need to protect the market with the need to accommodate the normal business operations of Self-Supply LSEs. Based on the results of such review, PJM shall propose either to modify or retain the existing Maximum Net Short and Net Long positions. The Office of the Interconnection shall post publicly and solicit stakeholder comment regarding the proposal. If, as a result of this process, changes to the Maximum Net Short and/or Net Long positions are proposed, the Office of the Interconnection shall file such modified Maximum Net Short and/or Net Long positions with the FERC by October 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

(iii) Process for Establishing a Capacity Resource with Actionable Subsidy.

(A) By no later than one hundred fifty (150) days prior to the commencement of the offer period of any RPM Auction conducted for the 2022/2023 Delivery Year and all subsequent Delivery Years, each Capacity Market Seller must specify, in accordance with the PJM Manuals, whether each Demand Resource, Generation Capacity Resource, and uprate, or planned uprate of a Generation Capacity Resource that the Capacity Market Seller intends to offer into the RPM Auction is a Capacity Resource with Actionable Subsidy in accordance with Tariff, Attachment DD, section 5.14(h)(ii). Notwithstanding, each Capacity Market Seller may subsequently disclaim Capacity Resource with Actionable Subsidy status by notifying the Office of Interconnection, in accordance with the PJM Manuals, that it elects to forego receiving any Material Subsidy for the applicable Delivery Year no later than thirty (30) days prior to the commencement of the offer period for the relevant RPM Auction. Within five (5) business days upon receipt of the request for additional information, the Capacity Market Seller shall provide any supporting information reasonably requested by the Office of the Interconnection or the Market Monitoring Unit to evaluate whether such Capacity Resource is a Capacity Resource with Actionable Subsidy.

(B) Once a Capacity Resource is a Capacity Resource with Actionable Subsidy, the status of such Capacity Resource will remain unchanged unless and until the Capacity Market Seller provides notification of a change in such status or the Office of the Interconnection removes such status pursuant to Tariff, Attachment DD, section 5.14(h)(vii), or by Commission order. All Capacity Market Sellers shall have an ongoing obligation to provide notification of any change in status.

(iv) Minimum Offer Price Rule. Any Sell Offer for a Capacity Resource with Actionable Subsidy that has not elected the Resource Carve–Out option in accordance with Tariff, Attachment DD, section 5.14(h)(vi) shall have an offer price no lower than the MOPR Floor Offer Price.

(A) MOPR Floor Offer Price. The determination of the MOPR Floor Offer Price for a Capacity Resource with Actionable Subsidy shall be dependent on whether such Capacity Resource (1) is a Generation Capacity Resource or a Demand Resource; (2) has previously cleared in an RPM Auction; or (3) has been subject to the Resource Carve-Out option since it last cleared an RPM Auction.

(1) For a Capacity Resource with Actionable Subsidy that has not cleared in an RPM Auction for any prior Delivery Year,

(a) if such resource is a Generation Capacity Resource, then the applicable MOPR Floor Offer Price shall be, at the election of the Capacity Market Seller, the resource-specific value determined in accordance with the resource-specific MOPR Floor Offer Price process in section 5.14(h)(v)(B)(2) below or the default MOPR Floor Offer Price for the applicable new resource type shown in the table below, as adjusted for Delivery Years subsequent to the 2022/2023 Delivery Year, net of Projected PJM Market Revenues for the resource.

Planned Resource Type	**Default MOPR Floor Offer Price (2022/2023 $/ICAP MW-day)***
Nuclear	$1,451
Coal	$1,023
Combined Cycle	$438
Combustion Turbine	$355
Hydro	$1,066
Solar PV	$387
Onshore Wind	$2,489
Offshore Wind	$4,327

* The MOPR Floor Offer Prices are expressed in dollars per Installed Capacity ("ICAP) MW-day, where the ICAP MW value for Solar PV, Onshore Wind and Offshore Wind is assumed to be 42.0%, 14.7%, and 26.0%, respectively, of the nameplate rating of these resource types.

Commencing with the Base Residual Auction for the 2023/2024 Delivery Year, the Office of the Interconnection shall adjust the default MOPR Floor Offer Prices in the table above, and post the adjusted values on its website, by no later than one hundred fifty (150) days prior to the commencement of the offer period for each Base Residual Auction. To determine the adjusted applicable MOPR Floor Offer Prices, the Office of the Interconnection shall utilize the same Applicable BLS Composite Index applied for such Delivery Year to adjust the CONE value used to determine the Variable Resource Requirement Curve, in accordance with Tariff, Attachment DD, section 5.10(a)(iv), and updated estimates of the net energy and ancillary service revenues for each default resource type.

Beginning with the Delivery Year that commences June 1, 2022, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall review the default MOPR Floor Offer Prices for the Capacity Resource with Actionable Subsidy that has not cleared in an RPM Auction for any prior Delivery Year. Such review may include, without limitation, analyses of the fixed development, construction, operation, and maintenance costs for such resource types. Based on the results of such review, PJM shall propose either to modify or retain the default MOPR Floor Offer Prices stated in the table above. The Office of the Interconnection shall post publicly and solicit stakeholder comment regarding the proposal. If, as a result of this process, changes to the default Avoidable Cost Rate values are proposed, the Office of the Interconnection shall file such proposed modifications with the FERC by October 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

(b) if such resource is a Demand Resource, then the applicable MOPR Floor Offer Price shall be the average Demand Resource Sell Offer price based on the previous three Base Residual Auctions for the LDA in which the Demand Resource is located, as posted by the Office of the Interconnection one hundred fifty (150) days before the relevant BRA for such Delivery Year.

(2) For a Capacity Resource with Actionable Subsidy that has cleared in an RPM Auction for any prior Delivery Year, or, as applicable, any Delivery Year since last electing to be subject to the Resource Carve-Out option,

(a) if such resource is a Generation Capacity Resource, then the applicable MOPR Floor Offer Price shall be, at the election of the Capacity Market Seller, (i) based on the resource-specific Avoidable Cost Rate net of the Projected PJM Market Revenues for the resource, as determined in accordance with Tariff, Attachment DD, section 5.14(h)(iv)(B)(3) below, or (ii) the default Avoidable Cost Rate for the applicable existing resource type shown in the table below, as adjusted for Delivery Years subsequent for the 2022/2023 Delivery Year to reflect changes in avoidable costs, net of Projected PJM Market Revenues for that resource.

Existing Resource Type	**Default ACR (2022/2023 (\$/ICAP MW-day)**
Nuclear - single	\$631

Nuclear - dual	$593
Coal	$171
Combined Cycle	$86
Combustion Turbine	$57
Hydro	$0
Pumped Hydro	$0
Solar PV	$0
Wind Onshore	$0

Commencing with the Base Residual Auction for the 2023/2024 Delivery Year, the Office of the Interconnection shall adjust the default Avoidable Cost Rates in the table above, and post the adjusted values on its website, by no later than one hundred fifty (150) days prior to the commencement of the offer period for each Base Residual Auction. To determine the adjusted Avoidable Cost Rates, the Office of the Interconnection shall utilize the same Applicable BLS Composite Index applied for such Delivery Year to adjust the CONE value used to determine the Variable Resource Requirement Curve, in accordance with section 5.10(a)(iv).

Beginning with the Delivery Year that commences June 1, 2022, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall review the default Avoidable Cost Rates for Capacity Resources with Actionable Subsidies that have cleared in an RPM Auction for any prior Delivery Year. Such review may include, without limitation, analyses of the avoidable costs of such resource types. Based on the results of such review, PJM shall propose either to modify or retain the default Avoidable Cost Rate values stated in the table above. The Office of the Interconnection shall post publicly and solicit stakeholder comment regarding the proposal. If, as a result of this process, changes to the default Avoidable Cost Rate values are proposed, the Office of the Interconnection shall file such proposed modifications with the FERC by October 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

(b) if such resource is a Demand Resource, then the applicable MOPR Floor Offer Price shall be zero dollars.

(3) For a Capacity Resource with Actionable Subsidy that previously elected the Resource Carve-Out option and not cleared in an RPM Auction for any Delivery Year since being the subject of a Resource Carve-Out option, the applicable MOPR Floor Offer Price shall be the historic MOPR Floor Offer Price that would have been applicable for the Capacity Resource at the time the Capacity Market Seller elected for such resource to take the Resource Carve-Out option plus the highest annual amortized cost of project investment (i.e., Avoidable Project Investment Recovery) that occurred since the election of the Resource Carve-Out option, as determined in accordance with Tariff, the Attachment DD, section 6.8, where the historic MOPR Floor Offer Price may be determined on a default basis in accordance with section 5.14(h)(iv)(A) or on a resource-specific basis in accordance with section 5.14(h)(iv)(B).

(B) Resource-specific MOPR Floor Offer Price. A Capacity Market Seller intending to submit a Sell Offer for a Capacity Resource with Actionable Subsidy in any RPM Auction may, at its election, submit a request for a resource-specific MOPR Floor Offer Price determination for such Capacity Resource with Actionable Subsidy no later than one hundred twenty (120) days before the relevant RPM Auction. Such a request may be in addition to, or in lieu of, a determination that such Capacity Resource is exempt from being a Capacity Resource with Actionable Subsidy via the Self-Supply Exemption. A resource-specific MOPR Floor Offer Price shall be consistent with (i) for a Capacity Resource that has not cleared in an RPM Auction for any prior Delivery Year, the competitive, cost-based, fixed, net cost of new entry were the resource to rely solely on revenues from PJM-administered markets net of Projected PJM Market Revenues; or (ii) for a Capacity Resource that has cleared in an RPM Auction for any prior Delivery Year, the competitive, cost-based, fixed, going-forward costs net of expected revenues from PJM-administered markets. The following requirements shall apply to requests for such determinations:

(1) The Capacity Market Seller shall submit a written request that includes all of the required documentation as described below and in the PJM Manuals.

(2) For a resource-specific MOPR Floor Offer Price for Capacity Resources for which a Sell Offer based on such resource has not cleared in an RPM Auction for any prior Delivery Year, as more fully set forth in the PJM Manuals, the Capacity Market Seller must include in its request documentation to support the fixed development, construction, operation, and maintenance costs of the Capacity Resource, as well as estimates of offsetting net revenues solely from PJM-administered markets.

The financial modeling assumptions for calculating Cost of New Entry shall be the same modeling assumptions used to determine Cost of New Entry for the RPM Auction parameters: (i) nominal levelization of gross costs, (ii) asset life of 20 years, (iii) no residual value, (iv) all project costs included with no sunk costs excluded, (v) use first year revenues, and (vi) weighted average cost of capital based on the actual cost of capital for the entity proposing to build the Capacity Resource. As more fully set forth in the PJM Manuals, supporting documentation for project costs may include, as applicable and available, a complete project description; environmental permits; vendor quotes for plant or equipment; evidence of actual costs of recent comparable projects; bases for electric and gas interconnection costs and any cost contingencies; bases and support for property taxes, insurance, operations and maintenance ("O&M") contractor costs, and other fixed O&M and administrative or general costs; financing documents for construction-period and permanent financing or evidence of recent debt costs of the seller for comparable investments; and the bases and support for the claimed capitalization ratio, rate of return, cost-recovery period, inflation rate, or other parameters used in financial modeling. In addition to the certification, signed by an officer of the Capacity Market Seller, the request must include a certification that the claimed costs accurately reflect, in all material respects, the seller's reasonably expected costs of new entry and that the request satisfies all standards for a resource-specific MOPR Floor Offer Price hereunder. The request also shall identify all revenue sources relied upon in the Sell Offer to offset the claimed fixed costs, including, without limitation, long-term power supply contracts, tolling agreements, or tariffs on file with state regulatory agencies, and shall demonstrate that such offsetting revenues are consistent, over a reasonable time period identified by the Capacity Market Seller, with the standard prescribed above. In making such demonstration, the Capacity Market Seller may rely upon forecasts of competitive electricity prices in the PJM Region based on well defined models that include fully documented estimates of future fuel prices, variable operation and maintenance expenses, energy demand, emissions allowance prices, and expected environmental or energy policies that affect the seller's forecast of electricity prices in such region, employing input data from sources readily available to the public. Documentation for net revenues also may include, as available and applicable, plant performance and capability information, including heat rate, start-up times and costs, forced outage rates, planned outage schedules, maintenance cycle, fuel costs and other variable operations and maintenance expenses, and ancillary service capabilities.

(3) For a Generation Capacity Resources for which a Sell Offer based on such resource has cleared in an RPM Auction for any prior Delivery Year, as more fully set forth in the PJM Manuals, the resource-specific MOPR Floor Offer Price shall be the Avoidable Cost Rate, as determined in accordance with Tariff, Attachment DD, section 6.8 net of Projected PJM Market Revenues. All supporting data must be provided for all requests.

(4) A Sell Offer evaluated under the resource-specific MOPR Floor Offer Price shall be permitted if the information provided reasonably demonstrates that the Sell Offer's costs (net of expected revenues from PJM-administered markets) is below the default MOPR Floor Offer Price, based on competitive cost advantages relative to the costs implied by the default MOPR Floor Offer Price, including, without limitation, competitive cost advantages resulting from the Capacity Market Seller's business model, financial condition, tax status, access to capital or other similar conditions affecting the applicant's costs, or based on net revenues that are reasonably demonstrated hereunder to be higher than those implied by the default MOPR Floor Offer Price. Capacity Market Sellers shall be asked to demonstrate that claimed cost advantages or sources of net revenue that are irregular or anomalous, that do not reflect arm's-length transactions, or that are not in the ordinary course of the Capacity Market Seller's business are consistent with the standards of this subsection. Failure to adequately support such costs or revenues so as to enable the Office of the Interconnection to make the determination required in this section will result in denial of a resource-specific MOPR Floor Offer Price hereunder by the Office of the Interconnection.

(v) Resource-specific MOPR Floor Offer Price and Exemption Process.

(A) The Office of the Interconnection shall post, by no later than one hundred fifty (150) days prior to the commencement of the offer period for an RPM Auction, a preliminary estimate for the relevant Delivery Year of the default MOPR Floor Offer Prices.

(B) The Capacity Market Seller must submit its request for a resource-specific MOPR Floor Offer Price or a Self-Supply Exemption, in writing simultaneously to the Market Monitoring Unit and the Office of the Interconnection by no later than one hundred twenty (120) days prior to the commencement of the offer period for the RPM Auction in which such seller seeks to submit its Sell Offer. The Capacity Market Seller shall include in its request a description of its Capacity Resource, whether the Capacity Market Seller is requesting a resource-specific MOPR Floor Offer Price or a Self-Supply Exemption, and all documentation necessary to demonstrate that the applicable criteria are satisfied, including without limitation the applicable certification(s) specified in this subsection 5.14(h). In addition to the documentation identified herein and in the PJM Manuals, the Capacity Market Seller shall provide any additional supporting information reasonably requested by the Office of the Interconnection or the Market Monitoring Unit to evaluate the Sell Offer. Requests for additional documentation will not extend the deadline by which the Office of the Interconnection or the Market Monitoring Unit must provide their determinations of the request. The Capacity Market Seller shall have an ongoing obligation through the closing of the offer period for the RPM Auction to update the request to reflect any material changes in the request.

(C) As further described in Section II.D of Attachment M-Appendix to this Tariff, the Market Monitoring Unit shall review the request and supporting documentation and shall provide its determination by no later than ninety (90) days prior to the commencement of the offer period for the relevant RPM Auction. The Office of the Interconnection shall also review all requests to determine whether the request is acceptable in accordance with the standards and criteria under this section 5.14(h) and shall provide its determination in writing to the Capacity Market Seller, with a copy to the Market Monitoring Unit, by no later than sixty-five (65) days prior to the commencement of the offer period for the relevant RPM Auction. The Office of the Interconnection shall reject a request if it does not comply with the PJM Market Rules, as interpreted and applied by the Office of the Interconnection. Such rejection shall specify those points of non-compliance upon which the Office of the Interconnection based its rejection of the exemption or resource-specific MOPR Floor Offer Price request. If the Office of the Interconnection does not provide its determination on a request by no later than sixty-five (65) days prior to the commencement of the offer period for the relevant RPM Auction, the request shall be deemed granted. Following the Office of the Interconnection's determination on a resource-specific MOPR Floor Offer Price request, the Capacity Market Seller shall notify the Market Monitoring Unit and the Office of the Interconnection, in writing, of the minimum level of Sell Offer, consistent with such determination, to which it agrees to commit by no later than sixty (60) days prior to the commencement of the offer period for the relevant RPM Auction. A Capacity Market Seller that is dissatisfied with any determination hereunder may seek any remedies available to it from FERC; provided, however, that the Office of the Interconnection will proceed with administration of the Tariff and market rules unless and until ordered to do otherwise by FERC.

(vi) Resource Carve-Out Option.

(aA) A Capacity Market Seller is eligible to elect the Resource Carve-Out option for a Capacity Resource with Actionable Subsidy owned by or contracted to such seller if the Capacity Resource is an annual Capacity Resource with an Actionable Subsidy that is subject to the Minimum Offer Price Rule. Election of the Resource Carve-Out shall exempt the Capacity Resource with an Actionable Subsidy from the Minimum Offer Price Rule.

(B) No less than thirty (30) days prior to the commencement of the offer period of the next Base Residual Auction, any Capacity Market Seller seeking to elect the Carved Out Resource option for a Capacity Resource with Actionable Subsidy shall notify the Office of the Interconnection in accordance with the process set forth in the PJM Manuals. Such election shall acknowledge that the Capacity Market Seller will not receive any revenues from the PJM capacity market for the Carved Out Resource. Such election shall extend for a period ending no sooner than when the Carved Out Resource is no longer entitled to a Material Subsidy. A Capacity Market Seller of a Carved Out Resource shall not be allowed to submit a Sell Offer for such Capacity Resource in an RPM Auction until such Capacity Resource is no longer entitled to receive a Material Subsidy.

(C) No less than thirty (30) days before the conduct of each Base Residual Auction, a Market Seller that elected the Resource Carve-Out option shall specify the UCAP amount in MWs that it elects to carve out up to the maximum allowable quantity, which shall be based on the lower of the generation resources' EFORd calculated based on outage data for the 12 months ending September 30th prior to the Base Residual Auction or the 5 Year Average EFORd based on outage data for the 12 months ending September 30th prior to the Base residual Auction.

(D) Any Carved Out Resource shall have a capacity commitment as if the resource had cleared in an RPM Auction and shall be subject to the charges set forth in Tariff, Attachment DD, sections 7, 9, 10, 10A, 11, and 13. Any Capacity Market Seller of a Carved Out Resource may cure deficiencies and avoid or reduce associated charges prior to the Delivery Year by procuring replacement Unforced Capacity outside of any RPM Auction and committing such capacity in place of a Carved Out Resource.

(E) For each Base Residual Auction for a Delivery Year within the period a Capacity Resource is the subject of a Resource Carve-Out, the Office of the Interconnection will deem that the Capacity Market Seller has submitted a Sell Offer for such Capacity Resource at a price of zero dollars. A Carved Out Resource is not eligible to offer available capacity or buy replacement capacity in an Incremental Auction.

(vii) Procedures and Remedies in Cases of Suspected Fraud or Material Misrepresentation or Omissions in Connection with a Capacity Resource with Actionable Subsidy

In the event the Office of the Interconnection, with advice and input from the Market Monitoring Unit, reasonably believes that a certification of a Capacity Resource's status contains fraudulent or material misrepresentations or omissions such that the Capacity Market Seller's Capacity Resource is, or is not, a Capacity Resource with Actionable Subsidy, then:

(A) the Office of the Interconnection will provide written notice of suspected fraudulent or material misrepresentation or omission to the Capacity Market Seller no later than sixty (60) days prior to the commencement of the offer period for the RPM Auction for which the seller submitted the certification. In such event, a resource that is a Capacity Resource with Actionable Subsidy shall be subject to the Minimum Offer Price Rule. The Office of the Interconnection shall make any filings with FERC that the Office of the Interconnection deems necessary. A Capacity Market Seller may challenge the Office of Interconnection's determination of suspected fraudulent or material misrepresentation or omission by filing a petition with FERC;

(B) if the Office of the Interconnection does not provide written notice of suspected fraudulent or material misrepresentation or omission at least sixty (60) days before the start of the relevant RPM Auction, then the Office of the Interconnection may file the certification that contains any alleged fraudulent or material misrepresentation or omission with FERC. The Office of the Interconnection shall implement any remedies ordered by FERC; and

(C) prior to applying the Minimum Offer Price Rule pursuant to this subsection 5.14(h)(vii), the Office of the Interconnection, with advice and input of the Market Monitoring Unit, shall notify the affected Capacity Market Seller and, to the extent practicable, provide the Capacity Market Seller an opportunity to explain the alleged fraudulent or material misrepresentation or omission. Any filing to FERC under this provision shall seek fast track treatment and neither the name nor any identifying characteristics of the Capacity Market Seller or the resource shall be publicly revealed, but otherwise the filing shall be public. The Capacity Market Seller may submit a revised certification for that Capacity Resource for subsequent RPM Auctions, including RPM Auctions held during the pendency of the FERC proceeding. In the event that the Capacity Market Seller is cleared by FERC from such allegations of fraudulent or material misrepresentations or omissions then the certification shall be restored to the extent and in the manner permitted by FERC. The remedies required by this subsection 5.14(h)(vii) to be requested in any filing to FERC shall not be exclusive of any other remedies or penalties that may be pursued against the Capacity Market Seller.

~~(1) For purposes of this section, the Net Asset Class Costs of New Entry shall be asset class estimates of competitive, cost-based nominal levelized Cost of New Entry, net of energy and ancillary service revenues. Determination of the gross Cost of New Entry component of the Net Asset Class Cost of New Entry shall be consistent with the methodology used to determine the Cost of New Entry set forth in Section 5.10(a)(iv)(A) of this Attachment.~~

~~The gross Cost of New Entry component of Net Asset Class Cost of New Entry shall be, for purposes of the 2018/2019 Delivery Year and subsequent Delivery Years, the values indicated in the table below for each CONE Area for a combustion turbine generator ("CT"), and a combined cycle generator ("CC") respectively, and shall be adjusted for subsequent Delivery Years in accordance with subsection (h)(2) below. For purposes of Incremental Auctions for the 2015/2016, 2016/2017 and 2017/2018 Delivery Years, the MOPR Floor Offer Price shall be the same as that used in the Base Residual Auction for such Delivery Year. The estimated energy and ancillary service revenues for each type of plant shall be determined as described in subsection (h)(3) below. Notwithstanding the foregoing, the Net Asset Class Cost of New Entry shall be zero for: (i) Sell Offers based on nuclear, coal or Integrated Gasification Combined Cycle facilities; or (ii) Sell Offers based on hydroelectric, wind, or solar facilities.~~

	~~CONE Area 1~~	~~CONE Area 2~~	~~CONE Area 3~~	~~CONE Area 4~~
~~CT $/MW-yr~~	~~132,200~~	~~130,300~~	~~128,900~~	~~130,300~~
~~CC $/MW-yr~~	~~185,700~~	~~176,000~~	~~172,600~~	~~179,400~~

~~(2) Beginning with the Delivery Year that begins on June 1, 2019, the~~

~~gross Cost of New Entry component of the Net Asset Class Cost of New Entry shall be adjusted to reflect changes in generating plant construction costs in the same manner as set forth for the cost of new entry in section 5.10(a)(iv)(B), provided, however, that the Applicable BLS Composite Index used for CC plants shall be calculated from the three indices referenced in that section but weighted 25% for the wages index, 60% for the construction materials index, and 15% for the turbines index, and provided further that nothing herein shall preclude the Office of the Interconnection from filing to change the Net Asset Class Cost of New Entry for any Delivery Year pursuant to appropriate filings with FERC under the Federal Power Act.~~

~~(3) For purposes of this provision, the net energy and ancillary services revenue estimate for a combustion turbine generator shall be that determined by section 5.10(a)(v)(A) of this Attachment DD, provided that the energy revenue estimate for each CONE Area shall be based on the Zone within such CONE Area that has the highest energy revenue estimate calculated under the methodology in that subsection. The net energy and ancillary services revenue estimate for a combined cycle generator shall be determined in the same manner as that prescribed for a combustion turbine generator in the previous sentence, except that the heat rate assumed for the combined cycle resource shall be 6.722 MMbtu/Mwh, the variable operations and maintenance expenses for such resource shall be $3.23 per MWh, the Peak-Hour Dispatch scenario for both the Day-Ahead and Real-Time Energy Markets shall be modified to dispatch the CC resource continuously during the full peak-hour period, as described in section 2.46, for each such period that the resource is economic (using the test set forth in such section), rather than only during the four-hour blocks within such period that such resource is economic, and the ancillary service revenues shall be $3198 per MW-year.~~

~~(4) Any Sell Offer that is based on:~~

~~i) a Generation Capacity Resource located in the PJM Region that is submitted in an RPM Auction for a Delivery Year unless a Sell Offer based on that resource has cleared an RPM Auction for that or any prior Delivery Year, or until a Sell Offer based on that resource clears an RPM auction for that or any subsequent Delivery Year; or~~

~~ii) a Generation Capacity Resource located outside the PJM Region (where such Sell Offer is based solely on such resource) that requires sufficient transmission investment for delivery to the PJM Region to indicate a long-term commitment to providing capacity to the PJM Region, unless a Sell Offer based on that resource has cleared an RPM Auction for that or any prior Delivery Year, or until a Sell offer based on that resource clears an RPM Auction for that or any subsequent Delivery Year, in any LDA for which a separate VRR Curve is established for use in the Base Residual Auction for the Delivery Year relevant to the RPM Auction in which such offer is submitted, and that is less than 90 percent of the applicable Net Asset Class Cost of New Entry or, if there is no applicable Net Asset Class Cost of New Entry, less than 70 percent of the Net Asset Class Cost of New Entry for a combustion turbine generator as provided in subsection (h)(1) above shall be set to equal 90 percent of the applicable Net Asset Class Cost of New Entry (or set equal to 70 percent of such cost for a combustion turbine, where there is no otherwise applicable net asset class figure), unless~~

~~the Capacity Market Seller obtains the prior determination from the Office of the Interconnection described in subsection (5) hereof. This provision applies to Sell Offers submitted in Incremental Auctions conducted after December 19, 2011, provided that the Net Asset Class Cost of New Entry values for any such Incremental Auctions for the 2012-13 or 2013-14 Delivery Years shall be the Net Asset Class Cost of New Entry values posted by the Office of the Interconnection for the Base Residual Auction for the 2014-15 Delivery Year.~~

~~(5) Unit-Specific Exception. A Sell Offer meeting the criteria in subsection (4) shall be permitted and shall not be re-set to the price level specified in that subsection if the Capacity Market Seller obtains a determination from the Office of the Interconnection or the Commission, prior to the RPM Auction in which it seeks to submit the Sell Offer, that such Sell Offer is permissible because it is consistent with the competitive, cost-based, fixed, net cost of new entry were the resource to rely solely on revenues from PJM-administered markets. The following process and requirements shall apply to requests for such determinations:~~

~~i) The Capacity Market Seller may request such a determination by no later than one hundred twenty (120) days prior to the commencement of the offer period for the RPM Auction in which it seeks to submit its Sell Offer, by submitting simultaneously to the Office of the Interconnection and the Market Monitoring Unit a written request with all of the required documentation as described below and in the PJM Manuals. For such purpose, the Office of the Interconnection shall post, by no later than one hundred fifty (150) days prior to the commencement of the offer period for the relevant RPM Auction, a preliminary estimate for the relevant Delivery Year of the minimum offer level expected to be established under subsection (4). If the minimum offer level subsequently established for the relevant Delivery Year is less than the Sell Offer, the Sell Offer shall be permitted and no exception shall be required.~~

~~ii) As more fully set forth in the PJM Manuals, the Capacity Market Seller must include in its request for an exception under this subsection documentation to support the fixed development, construction, operation, and maintenance costs of the planned generation resource, as well as estimates of offsetting net revenues. Estimates of costs or revenues shall be supported at a level of detail comparable to the cost and revenue estimates used to support the Net Asset Class Cost of New Entry established under this section 5.14(h). As more fully set forth in the PJM Manuals, supporting documentation for project costs may include, as applicable and available, a complete project description; environmental permits; vendor quotes for plant or equipment; evidence of actual costs of recent comparable projects; bases for electric and gas interconnection costs and any cost contingencies; bases and support for property taxes, insurance, operations and maintenance ("O&M") contractor costs, and other fixed O&M and administrative or general costs; financing documents for construction-period and permanent financing or evidence of recent debt costs of the seller for comparable investments; and the bases and support for the claimed capitalization ratio, rate of return, cost-recovery period, inflation rate, or other parameters used in financial modeling. Such documentation also shall identify and support any sunk costs that the Capacity Market Seller has reflected as a reduction to its Sell Offer. The request shall include a certification, signed by an officer of the Capacity Market Seller, that the claimed costs accurately reflect, in all material respects, the seller's reasonably expected costs of new entry and that the request satisfies all standards for an exception~~

~~hereunder. The request also shall identify all revenue sources relied upon in the Sell Offer to offset the claimed fixed costs, including, without limitation, long-term power supply contracts, tolling agreements, or tariffs on file with state regulatory agencies, and shall demonstrate that such offsetting revenues are consistent, over a reasonable time period identified by the Capacity Market Seller, with the standard prescribed above. In making such demonstration, the Capacity Market Seller may rely upon forecasts of competitive electricity prices in the PJM Region based on well-defined models that include fully documented estimates of future fuel prices, variable operation and maintenance expenses, energy demand, emissions allowance prices, and expected environmental or energy policies that affect the seller's forecast of electricity prices in such region, employing input data from sources readily available to the public. Documentation for net revenues also may include, as available and applicable, plant performance and capability information, including heat rate, start-up times and costs, forced outage rates, planned outage schedules, maintenance cycle, fuel costs and other variable operations and maintenance expenses, and ancillary service capabilities. In addition to the documentation identified herein and in the PJM Manuals, the Capacity Market Seller shall provide any additional supporting information reasonably requested by the Office of the Interconnection or the Market Monitoring Unit to evaluate the Sell Offer. Requests for additional documentation will not extend the deadline by which the Office of the Interconnection or the Market Monitoring Unit must provide their determinations of the Minimum Offer Price Rule exception request.~~

~~iii) A Sell Offer evaluated hereunder shall be permitted if the information provided reasonably demonstrates that the Sell Offer's competitive, cost-based, fixed, net cost of new entry is below the minimum offer level prescribed by subsection (4), based on competitive cost advantages relative to the costs estimated for subsection (4), including, without limitation, competitive cost advantages resulting from the Capacity Market Seller's business model, financial condition, tax status, access to capital or other similar conditions affecting the applicant's costs, or based on net revenues that are reasonably demonstrated hereunder to be higher than estimated for subsection (4). Capacity Market Sellers shall be asked to demonstrate that claimed cost advantages or sources of net revenue that are irregular or anomalous, that do not reflect arm's-length transactions, or that are not in the ordinary course of the Capacity Market Seller's business are consistent with the standards of this subsection. Failure to adequately support such costs or revenues so as to enable the Office of the Interconnection to make the determination required in this section will result in denial of an exception hereunder by the Office of the Interconnection.~~

~~iv) The Market Monitoring Unit shall review the information and documentation in support of the request and shall provide its findings whether the proposed Sell Offer is acceptable, in accordance with the standards and criteria hereunder, in writing, to the Capacity Market Seller and the Office of the Interconnection by no later than ninety (90) days prior to the commencement of the offer period for such auction. The Office of the Interconnection shall also review all exception requests and documentation and shall provide in writing to the Capacity Market Seller, and the Market Monitoring Unit, its determination whether the requested Sell Offer is acceptable and if not it shall calculate and provide to such Capacity Market Seller, a minimum Sell Offer based on the data and documentation received, by no later than sixty-five (65) days prior to the commencement of the offer period for the relevant RPM Auction. If the Office of the Interconnection determines that the requested Sell~~

~~Offer is acceptable, the Capacity Market Seller Shall notify the Market Monitoring Unit and the Office of the Interconnection, in writing, of the minimum level of Sell Offer to which it agrees to commit by no later than sixty (60) days prior to the commencement of the offer period for the relevant RPM Auction~~

RAA, SCHEDULE 8
PRO FORMA CHANGES

DETERMINATION OF UNFORCED CAPACITY OBLIGATIONS

A. For each billing month during a Delivery Year, the Daily Unforced Capacity Obligation of a Party that has not elected the FRR Alternative for such Delivery Year shall be determined on a daily basis for each Zone as follows:

Daily Unforced Capacity Obligation = OPL x Final Zonal RPM Scaling Factor x FPR

Where:

OPL = Obligation Peak Load, defined as_the daily summation of the weather-adjusted coincident summer peak, last preceding the Delivery Year, of the end-users in such Zone (net of operating Behind The Meter Generation, but not to be less than zero) for which such Party was responsible on that billing day, as determined in accordance with the procedures set forth in the PJM Manuals

Final Zonal RPM Scaling Factor = the factor determined as set forth in *sections* B *and* C *of this Schedule*

FPR = the Forecast Pool Requirement

Netting of Behind the Meter Generation for a Party with regard to Non-Retail Behind the Meter Generation shall be subject to the following limitation:

For the 2006/2007 Planning· Period, 100 percent of the operating Non-Retail Behind the Meter Generation shall be netted, provided that the total amount of Non-Retail Behind the Meter Generation in the PJM Region does not exceed 1500 megawatts ("Non-Retail Threshold"). For each Planning Period/Delivery Year thereafter, the Non-Retail threshold shall be proportionately increased based on load growth in the PJM Region but shall not be greater than 3000 megawatts. Load growth shall be determined by the Office of the Interconnection based on the most recent forecasted weather-adjusted coincident summer peak for the PJM Region divided by the weather-adjusted coincident peak for the previous summer for the same area. After the load growth factor is applied, the Non-Retail Threshold will be rounded up or down to the nearest whole megawatt and the rounded number shall be the Non-Retail Threshold for the current Planning Period and the base amount for calculating the Non-Retail Threshold for the succeeding planning period. If the

Non-Retail Threshold is exceeded, the amount of operating Non-Retail Behind the Meter Generation that a Party may net shall be adjusted according to the following formula:

Party Netting Credit = (NRT/ PJM NRBTMG) * Party Operating NRBTMG

Where: NRBTMG is Non-Retail Behind the Meter Generation

NRT is the Non-Retail Threshold

PJM NRBTMG is the total amount of Non-Retail Behind the Meter Generation in the PJM Region

The total amount of Non-Retail Behind the Meter Generation that is eligible for netting in the PJM Region is 3000 megawatts. Once this 3000 megawatt limit is reached, any additional Non-Retail Behind the Meter Generation which operates in the PJM Region will be ineligible for netting under this section.

In addition, the Party NRBTMG Netting Credit shall be adjusted pursuant to Schedule 16 of this Agreement, if applicable.

A Party shall be required to report to PJM such information as is required to facilitate the determination of its NRBTMG Netting Credit in accordance with the procedures set forth in the PJM Manuals.

B. Following the Base Residual Auction for a Delivery Year, the Office of the Interconnection shall determine the Base Zonal RPM Scaling Factor and the Base Zonal Unforced Capacity Obligation for each Zone for such Delivery Year as follows:

Base Zonal Unforced Capacity Obligation = (ZWNSP * Base Zonal RPM Scaling Factor * FPR) + Zonal Short-Term Resource Procurement Target

and

Base Zonal RPM Scaling Factor = ZPLDY/ZWNSP x [RUCO / (RPLDY x FPR)]

Where:

ZPLDY = Preliminary Zonal Peak Load Forecast for such Delivery Year

ZWNSP = Zonal Weather-Normalized Summer Peak for the summer season concluding four years prior to the commencement of such Delivery Year

RUCO = the RTO Unforced Capacity Obligation satisfied in the Base Residual Auction for such Delivery Year.

RPLDY = RTO Preliminary Peak Load Forecast for such Delivery Year.

For purposes of such determination, PJM shall determine the Preliminary RTO Peak Load Forecast, and the Preliminary Zonal Peak Load Forecasts for each Zone, in accordance with the PJM Manuals for each Delivery Year no later than one month prior to the Base Residual Auction for such Delivery Year. PJM shall determine the Updated RTO and Zonal Peak Load Forecasts in accordance with the PJM Manuals for each Delivery Year no later than one month prior to each of the First, Second, and Third Incremental Auctions for such Delivery Year. PJM shall determine the most recent Weather Normalized Summer Peak for each Zone no later than seven months prior to the start of the Delivery Year, and shall calculate the RTO Weather Normalized Summer Peak as the sum of the Weather Normalized Summer Peaks for all Zones.

C. The Final RTO Unforced Capacity Obligation for a Delivery Year shall be equal to the sum of the unforced capacity obligations satisfied through the Base Residual Auction and the First, Second, Third, and any Conditional Incremental Auctions for such Delivery Year. The unforced capacity obligation satisfied in an Incremental Auction may be negative if capacity is decommitted in such auction. T~~t~~he Final Zonal Unforced Capacity Obligation for a Zone shall be equal to such Zone's pro rata share of the Final RTO Unforced Capacity Obligation for the Delivery Year based on the Final Zonal Peak Load Forecast made one month prior to the Third Incremental Auction. The Final Zonal RPM Scaling Factor shall be equal to the Final Zonal Unforced Capacity Obligation divided by (FPR times the Zonal Weather Normalized Summer Peak for the summer concluding prior to the commencement of such Delivery Year).

D. 1. No later than five months prior to the start of each Delivery Year, the Electric Distributor for a Zone shall allocate the most recent Weather Normalized Summer Peak for such Zone to determine the Obligation Peak Load for each end-use customer within such Zone.

2. During the Delivery Year, no later than 36 hours prior to the start of each operating day, the Electric Distributor shall provide to PJM for each Party to this Agreement serving load in such Electric Distributor's Zone the Obligation Peak Load for all end-use customers served by such Party in such Zone. In providing such information, the Electric Distributor shall further allocate each Party's Obligation Peak Load by state. The daily Unforced Capacity Obligation of a Party for such Operating Day shall not be subject to change thereafter.

3. For purposes of such allocations, the daily sum of the Obligation Peak Loads of all Parties serving load in a Zone must equal the Zonal Obligation Peak Load for such Zone.

Attachment B

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

AFFIDAVIT OF ADAM J. KEECH
ON BEHALF OF PJM INTERCONNECTION, L.L.C.

A. Introduction

1. My name is Adam J. Keech. My business address is 2750 Monroe Blvd., Audubon, Pennsylvania, 19403. I currently serve as the Executive Director, Market Operations for PJM Interconnection, L.L.C. ("PJM"). I am submitting this affidavit on behalf of PJM in support of its initial submission, filed on October 2, 2018, in the paper hearing directed by the Federal Energy Regulatory Commission ("FERC") in its June 29, 2018 order.[1]

B. Work Experience and Responsibilities

2. I have served in my current position since 2016 but have served as Director or Senior Director of Market Operations since 2013 where I had very similar

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1 *Calpine Corp. v. PJM Interconnection, L.L.C.*, 163 FERC ¶ 61,236 (2018) ("June 29 Order").

responsibilities. The Market Operations Departments at PJM are responsible for technical design, implementation, and clearing of all PJM electricity markets and include the Day-Ahead Market Operations Department, the Real-Time Market Operations Department, the Market Simulation Department, the Capacity Market Operations Department, and the Interregional Market Operations Department. The responsibilities of these departments include the Day-ahead and Real-time Energy Markets, Day-Ahead Scheduling Reserve Market, Regulation, Synchronized Reserve and Non-Synchronized Reserve Markets, Financial Transmission Rights and Reliability Pricing Model auctions, the Market Efficiency Process, and Market-to-Market coordination between PJM and the Midcontinent Independent System Operator, Inc. and between PJM and the New York Independent System Operator, as well as coordination with other Balancing Authority Areas.

3. In my capacity as Executive Director of the Market Operations Departments, I am directly responsible for the development of market rule changes through PJM's stakeholder process, oversight of the technical implementation of rule changes, and ensuring that PJM's market operations processes and market clearing results adhere to the requirements detailed in the PJM Open Access Transmission Tariff ("Tariff"), the Reliability Assurance Agreement among Load Serving Entities in the PJM Region, and the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. As Executive Director of the Market Operations Departments, my basic responsibility is to make sure that PJM's markets are designed in a manner that leads to efficient, intuitive market outcomes that minimize the cost of procurement, meet system reliability needs, and incentivize market participants to act in a manner that promotes system reliability. Prior to assuming my leadership role in Market Operations, I served as Director of Dispatch for PJM where I was responsible for real-time system operations in the control room and compliance with North American Electric Reliability Corporation standards. Before that, I served as manager of PJM's Real-Time Market Operations Department for three years, where I was directly responsible for PJM's real-time markets including the Real-time Energy Market and the Regulation, Synchronized Reserve and Non-Synchronized Reserve Markets in addition to the Real-Time Security Constrained Economic Dispatch tool used by PJM's system operators.

4. I have worked at PJM since January 2003. I hold a Bachelor's of Science degree in Electrical Engineering from Rutgers University in New Brunswick, NJ, and a Master's of Science degree in Applied Statistics from West Chester University in West Chester, PA.

C. Accounting for Capacity Commitments from the Resource Carve-Out in Clearing Base Residual Auctions

a. PJM's Approach

5. To procure the appropriate amount of capacity in a Base Residual Auction while recognizing the capacity commitment borne by resources that elect the Resource Carve-Out option, PJM must account for such resources in the auction clearing process. In this context, "appropriate" means enough capacity to ensure that both the carved out

load, and the neighboring load that has purchased capacity to meet its obligation through the Base Residual Auction, procure the same reserve margin.

6. PJM has determined that the best approach is to include resources and load that have elected the Resource Carve-Out option to be included in the auction clearing process and account for the carve-out in settlement of the market during the Delivery Year. Simply put, this approach models the relationship between a subsidized resource and the load paying for the subsidy as financial rather than physical. This method has several benefits.

7. First, this approach is consistent with the physical reality of system operations. Whether a resource is subsidized or not has no bearing on how PJM will operate the transmission system or schedule and operate resources in real-time. The Carved Out Resource, like any other resource in PJM, will be economically scheduled to serve all PJM load, not just the subsidizing load. Models that remove the Carved Out Resource and subsidizing load from the Base Residual Auction completely suggest a physical relationship between the two that is inconsistent with system operations.

8. Second, this approach guarantees that carved out load, and load within the PJM footprint that has purchased capacity through the Base Residual Auction, are required to purchase capacity to meet the same reserve margin. This is important to maintain consistent reliability and costs across loads that have purchased capacity through the auction and those that have elected to carve out. Further, it ensures that if the Carved Out Resource is unavailable during a capacity emergency, the subsidizing load has purchased reserves to cover the potential unavailability of the Carved Out Resource and will not be "leaning" on the system.

9. Finally, PJM's proposed approach allows maximum flexibility for the cross-state trading of Renewable Energy Credits ("RECs") because it does not require the load paying for the REC to be locked in three years in advance. Because the subsidy will be handled as a financial transaction between the Carved Out Resource and the identified load, the subsidizing load does not need to be identified until shortly before the Delivery Year when market settlement occurs. This additional flexibility allows time for the state REC procurement processes to take place and be accurately accounted for in PJM's capacity auctions.

10. Under PJM's proposal, Carved Out Resources receive a commitment and are counted toward meeting the region-wide reliability requirement, as well as the reliability requirement of the Locational Deliverability Area ("LDA") in which they are located. Additionally, if the Carved Out Resource and carved out load are not located within the same LDA, PJM's proposal ensures that the Capacity Emergency Transfer Limit ("CETL") capability required for a Carved-Out Resource to serve load in a different LDA is correctly accounted for in the clearing of the auction.

b. Issues With Other Approaches

11. In early design discussions regarding how to implement the Resource Carve-Out option, PJM considered an alternate approach to account for Carved Out Resources and load in the Base Residual Auction. Under this alternate approach, the Carved Out Resource and the associated load would be fully removed from the auction and the market would be cleared absent these resources. However, due to the complexity of such a model and the restrictions it would impose on the subsidizing load, PJM declined to adopt this approach.

12. First, as stated previously, removing Carved Out Resources and their associated load from the Base Residual Auction is inconsistent with real-time operations. The Carved Out Resource will be used by PJM to serve all PJM load and the carved out load will be served by the most economic set of resources in PJM even if it is not the Carved Out Resource. The explicit linkage between a resource and load in the capacity market is fundamentally inconsistent with PJM's operation of its system.

13. Second, under the alternate approach, the amount of carved out load would need to be identified prior to the Base Residual Auction. Such a requirement would have significant impacts on the implementation and outcomes of the Base Residual Auction. Removing an amount of load from the auction that is equal to the unforced capacity capability of the Carved Out Resource would require carved out load to purchase a zero reserve margin. Shifting the Variable Resource Requirement ("VRR") curve by the unforced capacity capability of the Carved Out Resource would result in the carved out load purchasing enough capacity to meet the Installed Reserve Margin rather than the cleared reserve margin. Alternatively, removing enough load from the auction to ensure that the carved out load has procured enough resources to meet the cleared reserve margin from the auction would require: (i) knowing the reserve margin before the auction itself cleared; or (ii) iterating through the auction multiple times while adjusting the carved out load and the VRR curve until a steady state is reached. Given that there is no guarantee that iterating through the auction would converge to a solution, this approach does not present a feasible option for implementation. It would also mean that the VRR curves that PJM posts in the Planning Parameters each February that are used by many to simulate the auction would not be same VRR curves used in the auction itself, as they would need to be augmented in some unknown way to implement the Resource Carve-Out option.

14. Finally, the alternate approach would require further enhancements to determine if, and how, subsidies involving a Carved Out Resource could serve carved out load in a different location. There are two ways to address this issue and both have significant drawbacks.

15. One option is to make a rule that the Carved Out Resource and load must be in the same constrained LDA. This is difficult to enforce and is also restrictive. The difficulty in enforcement stems from the fact that constrained LDAs are not known prior to the execution of the Base Residual Auction, which is when a Capacity Market Seller must elect the Resource Carve-Out option. To resolve this, an even more restrictive rule

could be put in place to require Carved Out Resources and load to be located within the same modeled LDA. A rule of this nature would limit the ability of renewable resources to sell RECs to neighboring states and therefore impede states' ability to meet their renewable energy targets.

16. A second option is to formulate a process to decrement the CETLs used in the auction to reserve some portion of that capability for Carved Out Resources and carved out loads in different LDAs. Without this step, there would be no guarantee that the sum of the CETL used by the Resource Carve-Out option plus that used in the market clearing adheres to the limit. Implementing this option would add additional complexity to the clearing process because the utilization of the CETL will depend on the amount of carved out capacity and load, which will also depend on the reserve margin. Moreover, doing so would preferentially hold out transfer capability for Carved Out Resources before making the remaining transfer capability available to all other load in an impacted LDA. Given the significant challenges presented by this approach, PJM declined to adopt it in favor of the proposal set forth in this filing.

D. Establishing Default MOPR Floor Offer Prices for Capacity Resources with Actionable Subsidies

a. Default MOPR Floor Offer Prices for Resources that have Never Cleared an RPM Auction shall be Based on the Construction and Development Costs of that Resource Type

17. PJM is proposing to allow sellers of Capacity Resources with Actionable Subsidies to use default Minimum Offer Price rule ("MOPR") Floor Offer Prices. PJM will annually post the default values for eight distinct generation resource types 150 days in advance of the relevant Reliability Pricing Model ("RPM") Auction. For such Capacity Resources that have never cleared an RPM Auction, these values will be based on an estimate of the levelized annual cost to construct and develop each resource type netted against an estimated energy and ancillary services ("E&AS") market revenue for each resource type to determine the default MOPR Floor Offer Prices. Accordingly, PJM is proposing to establish in the Tariff stated default costs for each resource type, as shown in Table 1 below. The Tariff-stated values will be used for the 2022/2023 Delivery Year Base Residual Auction. The table includes the E&AS revenues and the resulting MOPR Floor Offer prices.

Table 1: Estimated New Entry Default MOPR Floor Offer Prices

	Default MOPR Floor Offer Prices, $/ICAP MW-day[2]		
Planned Resource Type	**Cost of New Entry**	**Estimated E&AS Revenue Offset**	**MOPR Floor Offer Prices net of E&AS Revenues**
Nuclear	$1,817	$366	$1,451
Coal	$1,067	$45	$1,023
Combined Cycle	$523	$85	$438
Combustion Turbine	$380	$26	$355
Hydro	$1,177	$111	$1,066
Solar PV	$627	$240	$387
Onshore Wind	$3,670	$1,180	$2,489
Offshore Wind	$5,507	$1,180	$4,327

18. PJM developed these default MOPR Floor Offer prices based on information from a data base of the National Renewable Energy Laboratory ("NREL").[3] The NREL data is publicly available and includes overnight capital costs and the fixed operating and maintenance expense ("FOM") for nuclear, coal, hydro, solar photovoltaic, onshore wind, and offshore wind technologies. The costs used are as projected for 2022.

19. Utilizing the NREL data, the next step in developing the default MOPR Floor Offer prices is to convert the overnight capital cost to a levelized annual cost by multiplying the capital cost by a carrying charge rate. As an approximation, PJM used a carrying charge rate of ten percent based on the relationship between levelized annual

2 The MOPR Floor Offer Prices are expressed in dollars per Installed Capacity ("ICAP") MW-day, where the ICAP MW value for Solar PV, Onshore Wind, and Offshore Wind is assumed to be 42.0%, 14.7%, and 26.0%, respectively, of the nameplate rating of these resource types.

3 *See NREL Annual Technology Baseline (ATB)*, http://www.atb.nrel.gov (last visited Oct. 2, 2018).

charges and overnight capital cost for combined cycle and combustion turbine estimated by Brattle in the 2018 quadrennial study of Cost of New Entry ("CONE").[4]

20. Combined cycle and combustion turbine levelized annual costs are based on 2021/2022 Base Residual Auction Planning Parameters escalated to 2022/2023. The average of the four CONE areas was used as the regional transmission organization CONE value.

21. The estimated E&AS revenue offset represent a low E&AS offset based on the lowest zonal E&AS value estimated for each resource class type over the past three calendar years. The lowest zonal value is an appropriate value to utilize in developing a single estimated E&AS revenue value for each planned resource type across the entire PJM Region given the existence of an alternative, resource-specific MOPR Price option.

22. PJM's proposed default values are for the 2022/2023 Delivery Year, and therefore must be escalated to account for inflation and other increases in costs that occur over time. PJM proposes to adjust these values annually by adjusting the CONE values of Table 1 by applying the same Applicable Bureau of Labor and Statistics ("BLS") Composite Index used to adjust the CONE value of the VRR curve. The updated Default MOPR Floor Offer Prices will be posted 150 days before the applicable RPM Auction.[5]

23. PJM recognizes that the base values need to be revisited periodically. Accordingly, PJM will consider such default Avoidable Cost Rates as part of a robust stakeholder process that reviews the VRR Curve and CONE estimates once every four years.

24. Demand Resources provide capacity through a commitment to reduce peak energy usage when called upon by PJM, and the means for achieving such reduction can take numerous forms and can be derived from many different types of consumption. In light of this variability quantifying default costs to develop new Demand Resources is unworkable.

25. Given the uncertainty of cost data, Sell Offers submitted for Demand Resources in previous Base Residual Auctions provide the best indicator of their costs, and therefore can be relied upon to provide a reasonable MOPR Floor Offer Price for such resources. To smooth out yearly variations, the historical average of all Demand Resource offers submitted in the last three Base Residual Auctions in the LDA in which the Demand Resource is located should be the MOPR Floor Offer Price for Demand

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4 *See PJM Cost of New Entry - Combustion Turbines and Combined-Cycle Plants with June 1, 2022 Online Date*, https://www.pjm.com/~/media/committees-groups/committees/mic/20180425-special/20180425-pjm-2018-cost-of-new-entry-study.ashx.

5 *See infra* Table 2: Existing Resource Default Avoidable Cost Rates.

Resources that have never cleared any RPM Auction. PJM will post such values 150 days before the Base Residual Auction for that Delivery Year.

b. Default MOPR Floor Offer Prices for Existing Resources shall be Based on the Avoidable Cost Rate of that Resource Type

26. Just as for Capacity Resources with Actionable Subsidies that have never before cleared an RPM Auction, PJM is proposing that sellers of existing resources, i.e., Capacity Resources with Actionable Subsidies that have cleared an RPM Auction, may opt to use default Avoidable Cost Rate values in determining the applicable MOPR Floor Offer Price.

27. PJM proposes to include in the Tariff the default Avoidable Cost Rates for existing generation resources presented in Table 2 below, and to use those values for the 2022/2023 Delivery Year Base Residual Auction. For subsequent Delivery Years, PJM will annually adjust those values using the Applicable BLS Composite Index. The adjusted values will be posted on its website 150 days in advance of each Base Residual Auction.

Table 2: Existing Resource Default Avoidable Cost Rates

Existing Resource Type	Avoidable Cost Rates in $/ICAP MW-day[6]
Nuclear - single	$631
Nuclear - dual	$593
Coal	$171
Combined Cycle	$86
Combustion Turbine	$57
Hydro	$0
Pumped Hydro	$0
Solar PV	$0
Wind Onshore	$0

6 The Avoidable Cost Rate values for Hydro, Pumped Hydro, Solar PV and Onshore Wind were estimated to were estimated to be $66/ICAP MW-day, $25/ICAP MW-day, $168/ICAP MW-day and $457/ICAP-MW day, respectively, which are significantly lower than the relevant net E&AS revenues for these resource types.

28. Although the costs before the E&AS offset for hydro, pumped hydro, solar photovoltaic and onshore wind are greater than zero, PJM proposes to set the default Avoidable Cost Rate values for these resources at $0 because even the most conservative (low-end) estimate of net E&AS revenues in $/ICAP MW-day, for these resources, which are $111, $110, $240, and $1,180, respectively, would result in negative default MOPR Floor Offer Prices.

29. PJM relied on publicly available Environmental Protection Agency ("EPA") data in developing the existing resource default MOPR prices. PJM has previously relied on the EPA report in developing internal studies.[7] The EPA database provides FOM and Variable Operations & Maintenance ("VOM") cost data for new and existing generation resources, and the data is periodically updated with revised cost estimates. The data also provides unit-specific FOM and VOM values for existing nuclear units. EPA developed the data based on FERC Form 1 data submissions by resource owners.

30. The data PJM relied on includes the FOM of existing units. The EPA data base utilizes model plants to represent aggregations of actual individual generating units. Units with similar characteristics are grouped for representation by model plants with combined capacity and weighted-average characteristics that are representative of all the units comprising the model plant. Except for existing nuclear units, PJM averaged the FOM costs for the model plants in the PJM Region. PJM obtained existing nuclear unit FOM data from Table 4-34 "Characteristics of Existing Nuclear Units" of the EPA Base Case report.

31. Because the EPA's data are presented in 2011 dollars, PJM needed to escalate the value to 2022/2023 dollars, as that is the relevant Delivery Year. To do so, first PJM escalated them from 2011 to 2017 by historical year by year escalation using the Applicable BLS Composite Index. Then, consistent with PJM's longstanding practice of escalating Avoidable Cost Rate values for future years, PJM used the ten year historical average of the Applicable BLS Composite Index. PJM determined 1.026% to be the ten year average escalation rate for the 2008-2017 period. Combined these two escalations (for 2011-2017 and for 2017-2022) are equivalent to factor of 1.254. Thus, to arrive at the values stated in the above table, PJM multiplied the 2011 EPA values by 1.254.

32. While sellers may elect to use default Avoidable Cost Rate values for their resource, all E&AS revenue offsets will be determined based on the specific resource, The net E&AS revenues for an existing resource are derived using the actual

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7 PJM utilized the EPA data in developing internal and external reports, such as its Economic and Reliability Analysis of EPA's Final Clean Power Plan. *See EPA's Final Clean Power Plan – Compliance Pathways Economic and Reliability Analysis*, PJM Interconnection, L.L.C., https://www.pjm.com/~/media/library/reports-notices/clean-power-plan/20160901-cpp-compliance-assessment.ashx. Notably, EPA data used in this analysis includes FOM costs of nuclear and coal generators.

revenues received by the unit as described in Tariff, Attachment DD, section 6.8(d).[8] This is true whether the resource elects to use the default Avoidable Cost Rate or elects the resource-specific MOPR process, in which case the actual avoidable costs of the resource are provided and used in place of the applicable default Avoidable Cost Rate.

33. For Existing Demand Resources, PJM was unable to determine any material avoidable costs associated with a resource type. Costs associated with Demand Resources typically include up front metering and software installations that are applicable to Planned Demand Resources and not Existing ones. Given this, and the difficulty in implementing a resource-specific process for Existing Demand Resources, it is appropriate to provide in the Tariff that the MOPR Floor Offer Price for existing Demand Resources is zero dollars.

E. Establishing a Material Size Threshold of 20 Megawatts for Capacity Resources with Actionable Subsidies Appropriately Limits the Solar and Wind Resources that may be Subject to the MOPR

34. It is appropriate to set a size materiality threshold in applying the MOPR (and the Resource Carve-Out) so as to exclude resources of significant size that individually or collectively cannot exert much downward pressure on price outcomes. To this end, PJM proposes to retain its historic MOPR materiality threshold of 20 MW Unforced Capacity.[9]

35. A byproduct of such a materiality threshhold on resources subject to the MOPR is that it excludes from MOPR certain existing solar and wind resources in PJM. The PJM region hosts a total Unforced Capacity of existing solar and wind generation resources of 1560 MW. Approximately 931 MW are from resources that have an Unforced Capacity below 20 MW. Accordingly, this 931 MW of Unforced Capacity would be exempt from the MOPR.[10]

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8 *See* Tariff, Attachment DD, section 6.8(d) (Sept. 1, 2016).

9 It is important to recall that a resource's Unforced Capacity is less than its installed or nameplate capacity, because Unforced Capacity represents the megawatt quantity of energy that the resource can reliably contribute during peak hours. To determine a resource's Unforced Capacity value, PJM applies a capacity factor that can be a default value or a resource-specific value based on the operating history of the resource. For 2017, the default capacity factors for wind varied from 14.7% to 17.6%, and for solar from 38.0% to 60.0%. *See* Class Average Capacity Factors Wind and Solar Resources, PJM Interconnection, L.L.C. (June 1, 2017), https://www.pjm.com/-/media/planning/res-adeq/class-average-wind-capacity-factors.ashx?la=en. PJM Manual 21, Appendix B details how to calculate resource-specific capacity factors for wind and solar resources.

10 The installed capacity of these resources is 5,469 MW.

36. That leaves 629 MW of existing solar and wind resources that meet the materiality size standard and are potentially subject to the MOPR.[11] However, even if those 629 MW met all the other criteria for being a Capacity Resource with Actionable Subsidy, those resources likely would face little consequence by being subject to the MOPR. As I discuss above, the expected MOPR Floor Offer Prices for existing wind and solar units will be zero dollars, given the low going-forward costs and expected market revenues of these resources.

37. As for planned solar and wind resources, no one can accurately predict how many of the 13,847 MW of such resources with an Unforced Capacity 20 MW or greater currently in PJM's interconnection queue will achieve commercial operation. However, we can estimate, based on historical experience, the likelihood that each of these projects will achieve commercial operation.

38. PJM develops commercial probability models based on data from projects that have either achieved in-service status or have withdrawn from PJM's interconnection queue. The models are estimated using logistic regression considering the following factors: queue stage, fuel type, location (state), size, and project type (new project or uprate to existing project). The models are then used to calculate commercial probabilities for those projects that have not yet achieved resolution – active, under construction, or suspended. As a result, the calculated commercial probabilities for these projects implicitly assume that historical market and regulatory dynamics that have influenced the interconnection queue in the past will continue to influence it in a similar manner in the future.

39. The table below shows that most solar and wind projects in the interconnection queue are unlikely to actually achieve commercial operation. In fact, PJM estimates that, of the planned solar and wind resources with an Unforced Capacity of 20 MW or greater, only 624 MW have a 50% or greater likelihood of achieving commercial operation. All values shown in the table are Unforced Capacity.

Table 3: Planned Wind and Solar Resources in the PJM Interconnection Queue

Planned Resources (UCAP MW) - *In the PJM Interconnection Queue as of September 21, 2018*

MW of Planned Wind / Solar Resources Subject to Proposed MOPR Based on Project's Commercial Probability					
	0% - 24%	25% - 49%	50% - 74%	75% - 100%	TOTAL
Solar	10,351	1,095	112	350	*11,907*
Wind	1,752	26	52	110	*1,940*
TOTAL	12,103	1,121	164	460	*13,847*

11 Of this 629 MW, 423 MW are solar resources and 206 MW are wind resources.

40. By contrast, there are only about 322 MW of planned solar and wind resources with an Unforced Capacity *less than* 20 MW currently in PJM's interconnection queue, and those resources would be exempt from the MOPR.

41. This concludes my Affidavit.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

Adam J. Keech, being first duly sworn, deposes and states that he is the Adam J. Keech referred to in the foregoing document entitled "Affidavit of Adam J. Keech on Behalf of PJM Interconnetion, L.L.C.," that he has read the same and is familiar with the contents thereof, and that the facts set forth therein are true and correct to the best of his knowledge, information, and belief.

Adam J. Keech

Subscribed and sworn to before me, the undersigned notary public, this 1st day of October 2018.

Linda Spreeman
Notary Public

My Commission expires: Nov 17, 2019

COMMONWEALTH OF PENNSYLVANIA
NOTARIAL SEAL
Linda Spreeman, Notary Public
Lower Providence Twp., Montgomery County
My Commission Expires Nov. 17, 2019
MEMBER, PENNSYLVANIA ASSOCIATION OF NOTARIES

Attachment C

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

AFFIDAVIT OF HUNG-PO CHAO, Ph.D.
ON BEHALF OF PJM INTERCONNECTION, L.L.C.

A. Introduction

1. My name is Hung-po Chao. My business address is 2750 Monroe Blvd., Audubon, Pennsylvania, 19403. I am Senior Director, Economics, of PJM Interconnection, L.L.C. ("PJM"), as well as PJM's Chief Economist. I am submitting this affidavit on behalf of PJM in support of PJM's initial submission in the paper hearing ordered by the Federal Energy Regulatory Commission ("Commission") in its June 29, 2018 order[1] in this proceeding. In particular, I support the "Extended Resource Carve-Out" that PJM has proposed for Commission consideration and adoption to the extent the Commission finds that the Resource Carve-Out ("RCO"), standing alone, would have unacceptable adverse effects on the wholesale capacity market.

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1 *Calpine Corp. v. PJM Interconnection, L.L.C.*, 163 FERC ¶ 61,236 (2018) ("June 29 Order").

B. Work Experience and Responsibilities

2. I joined PJM in March 2016. In my capacity as Senior Director and Chief Economist, I advise the PJM executive team and the market services staff on economic policy and analysis, activities related to market design and evolution, market operations and market analysis, including those in the energy, capacity, ancillary services, and financial transmission rights markets. Prior to joining PJM, I was President of Energy Trading Analytics, advising companies and governments with problem-solving and energy policy analytics. Previously, I was Director, Market Monitoring, and later Director, Market Strategy and Analysis, at ISO New England Inc. Earlier, I held various technical and management positions with the Electric Power Research Institute, Inc. ("EPRI"). During my time at EPRI, I was responsible for the Environmental Risk Analysis Area, founded the Power Market Design Initiative, and received the Chauncey Starr Award (named for the founding president of EPRI) for "creating a world-class analytical capability for electricity market design."

3. I have served as a visiting professor at University of California, Berkeley where I taught courses in operations research and I was also a consulting professor at Stanford University where I taught a graduate-level course on the economic analysis of market organizations. I serve on the Editorial Board of the *Journal of Regulatory Economics.* I have authored or co-authored over sixty papers published in leading professional journals including *American Economic Review*, *Operations Research*, *Journal of Economic Review*, and *Electricity Journal.* I co-edited and co-authored "Designing Competitive Electricity Markets" published by Kluwer Academic Publishers in 1998.

4. I hold the degree of Bachelor of Science in Electrical Engineering from National Taiwan University, and graduate degrees of Master of Science in Statistics, Master of Science in Operations Research, and Doctor of Philosophy in Operations Research (major) and Economics (minor), all from Stanford University.

C. Overview

5. My analysis accepts that state subsidies for in-state production may be justified in certain circumstances. The Commission's June 29 Order implicitly takes this position by suggesting a resource-specific carve-out, as did PJM by proposing a state accommodation alternative in its original filing in this case. Well-accepted economic doctrine provides a respected framework for acknowledging state subsidies. Specifically, a state-sponsored subsidy program to assist domestic production could, in principle, be justified as a second-best policy intervention to promote the economic welfare of the state when there is a "domestic divergence." Under this theory, developed in the area of international trade policy and economic welfare over sixty years ago by a world leading economist,[2] domestic divergence refers to an external divergence between the marginal

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2 The domestic divergence doctrine was pioneered by British economist James Meade, who won the 1977 Nobel Prize in Economics jointly with Swedish

social cost (or value) of particular domestic production and the marginal private cost (or value) of that production. For example, in the context of the wholesale electricity market, a domestic divergence may arise from the perceived beneficial external impacts of favored types of in-state generation on the environment or local job markets. Note, however, that economic theory distinguishes among types of divergences between marginal private costs and marginal social costs. If a marginal divergence is caused by a market imperfection or externality of some kind then it is not considered a distortion. By contrast, if a divergence is caused by a domestic state policy that is not tailored to address a market imperfection or externality, it is categorized as a market distortion.

6. Importantly, any subsidy to a resource, even if it responds to an in-state (i.e., domestic) divergence caused by a market imperfection or externality, can be expected to have two distinct consequences in the broader market, i.e., price suppression and resource substitution. In effect, a subsidy suppresses market price and expands its output, because it shifts the supply curve downward and to the right. But the magnitude of these effects will vary, depending on the subsidy and the market context. Moreover, whether these effects are significant enough to warrant mitigative or corrective actions is a distinct question for the Commission. In the accompanying filing, PJM proposes certain terms and conditions on the RCO that would reduce or mitigate these effects to such an extent that the Commission could find that the market remains just and reasonable. At the same time, PJM recognizes that the Commission could also find that the expected adverse market effects of the RCO warrant further action. For that purpose, PJM (with my advice and input) has developed for Commission consideration an Extended RCO, with three main features:

i. Determination of a competitive auction clearing price and quantity based on economic supply offers (i.e., excluding uneconomic resources that elect the RCO rather than submitting an economic offer determined under the Minimum Offer Price Rule ("MOPR")) and all load subject to the Variable Resource Requirement on the power system (i.e., including in the auction load deemed associated with resources that elected the RCO);

ii. Paying resources only for the infra-marginal rent portion of the market clearing price (the difference between the market clearing price and the offer) if their offers were infra-marginal helping set the clearing price determined in (i) but *did not clear* solely due to commitment of the uneconomic resources that elected the RCO; and

iii. Recovering the cost of those infra-marginal rent payments in (ii) from the resource owners that elect the RCO, since their market choice to commit an uneconomic resource is the direct cause of crowding out the infra-marginal offers of economic resources.

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economist Bertil Ohlin. *See* James E. Meade, Trade and Welfare, Chapter 14 (1st ed. 1955); *see also* W. Max Corden, Trade Policy and Economic Welfare (2d ed. 2002).

7. Assuming the Commission finds that the RCO presents a risk of more significant adverse market effects that warrant further mitigation, I show in this affidavit that these elements of the Extended RCO proposal will reasonably meet that need.

D. Determination of Clearing Price Using Economic Offers

8. As noted above, subsidies inherently present a risk of price suppression, but whether the effects are adverse and material will depend on the circumstances. In the simplest terms, a subsidy shifts the supply curve of the resource to the right and downward. With all else equal, a subsidized offer tends to suppress price as the seller is able to offer below its economic costs, which will tend to reduce the clearing price below the efficient level that would be set by economic offers, giving rise to market distortions that reduce the long-run efficiency and the social value of the market. The adverse economic effects associated with subsidies are well-documented in the peer-reviewed economic literature on, and modeling of, wholesale electric capacity markets.[3] Similarly, the Commission has repeatedly found that out-of-market subsidies for certain resources will suppress capacity market clearing prices below the level needed to facilitate efficient resource entry and exit and ensure satisfaction of resource adequacy objectives. Indeed, that is the stated rationale for the Commission's conclusion in the June 29 Order that PJM's current MOPR is unjust and unreasonable.

9. While I am not addressing whether the RCO, standing alone, will cause price suppression at a level that warrants corrective action, I do note that the economic effects of the RCO generally should be expected to be the same as those that would result from the subsidized resource submitting an offer at zero price. If a subsidized (state-sponsored) resource is allowed to satisfy a fixed quantity of demand carved out of the capacity auction, it would have the same economic effects (price suppression and resource substitution) on the capacity market as a zero-price offer in the capacity market.

10. If there is concern that auction prices will be suppressed by committing an uneconomic resource, there could be several reasonable ways to determine a competitive price. One could determine (and submit in the auction) an economic offer price for the

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3 *See, e.g.*, David Brown, The Effect of Subsidized Entry on Capacity Auctions and the Long-Run Resource Adequacy of Electricity Markets 205-232, *Energy Economics*, Vol. 70 (2018); R.J. Briggs, & Andrew Kleit, Resource Adequacy Reliability and the Impacts of Capacity Subsidies in Competitive Electricity Markets 297-305, *Energy Economics*, Vol. 40 (2013); Seth Blumsack et al., *Analysis of State Policy Interactions with Electricity Markets in the Context of Uneconomic Existing Resources: A Critical Assessment of the Literature*, Pennsylvania State University (Sept. 28, 2018), https://www.eme.psu.edu/sites/default/files/files/Penn%20State%20Study%20FINAL.pdf.

resource, as is done in the MOPR process. Alternatively, one could rely on all economic offers actually submitted in the auction to determine a competitive clearing price. PJM proposes the latter approach in this filing. For that purpose, all offers from resources for which the RCO has not been elected are economic offers, including any mitigation of such offers under MOPR or other provisions of the PJM Open Access Transmission Tariff. This price determination reasonably includes loads that are identified with the resource that elected the RCO (without changing the RCO rule that those loads are not charged the auction clearing price with respect to that resource). Otherwise, as I explain above, removing both the load and the resource that elect the RCO in the price determination stage would be economically equivalent to the RCO resource submitting an uneconomic and unmitigated zero-price offer, which would maintain the price suppression and negate the intended mitigation.

11. Assuming the Commission finds that the RCO presents a price suppression risk that warrants further mitigation, my analysis shows that the Extended RCO proposal should reasonably address the risk. Next, my affidavit will address the resource substitution effect that remains due to commitment of the uneconomic resources that choose the RCO crowding out the infra-marginal offers of economic resources.

E. Paying Infra-Marginal Resources that Do Not Clear the Infra-Marginal Rent

12. As I noted above, committing an uneconomic resource causes not only price suppression, but also resource substitution. Substitutional effects, which are a common topic of economic analysis,[4] in this context means a subsidized uneconomic resource displaces an economic resource that submitted an infra-marginal offer and thus would have been selected by the market to meet demand. It is well-accepted in economics that such resource substitution can impose significant costs, reducing the social benefits measured by the market surplus. To explain this, I discuss below: (i) the role of infra-marginal rents in the capacity market; (ii) the fundamental role in competitive markets of tradable rights, which include the infra-marginal rents for competitive resources; (iii) how the adverse effects caused by uneconomic resource substitution can be mitigated by paying infra-marginal rents to the displaced infra-marginal resource; and (iv) how such a payment of infra-marginal rents preserves reasonable price signals and incentives to submit competitive offers.

13. The goal of a capacity market is to ensure resource adequacy and revenue sufficiency. The capacity market price will rise to the extent the net revenue from energy and ancillary services is insufficient to cover investment costs and returns. The capacity market rests on the premise that the competitively distributed infra-marginal rents will be sufficient to induce efficient entry and exit decisions. Under current capacity market conditions, the cost of new entry is sensitive to the dynamics of electricity pricing and the capacity mix. Consequently, resource offers vary across diverse technologies, producing

4 *See* Joseph E. Stiglitz & Jay K. Rosengard, Economics of the Public Sector (4th ed. 2015).

a sloped supply curve and potentially significant infra-marginal rents for offers below the supply curve-demand curve intersection.[5]

14. The type of resource substitution at issue here imposes costs because it will tend to cause the capacity market outcome to deviate from equilibrium where the market surplus is maximized. The economic cost associated with the resource substitution effects can be estimated by the reduction of the market surplus (also often referred to as "dead-weight loss"). Suppose that in a competitive capacity market, offer prices accurately reflect suppliers' true marginal opportunity costs for undertaking capacity commitments. Given the competitive clearing price, the economic efficiency losses (or dead-weight losses) associated with the substitutional effects would equal the sum of the infra-marginal rents (or net revenues) earned by the substituted resources in the capacity market before the substitution takes place. The infra-marginal rent is a type of economic rent for each resource that equals the difference between the market price and the resource's offer price.

15. Importantly, such infra-marginal rents are a form of tradable rights. Competitive markets are built on tradable rights. The infra-marginal rents play an important function in a market economy. Simply put, they compensate not only investments in tangible assets such as generating units but also investments in intangible assets (such as research and development) that foster efficiency and innovation. These rents reflect the value of innovation and encourage future innovation. In a competitive market, investors are allowed to freely submit offers in exchange for infra-marginal rents, which are considered an economic form of tradable rights. Infra-marginal rent is not only a core element in the structure of price formation, but also an essential risk instrument used by investors to finance investments in tangible and intangible capital assets fostering productive, diverse, and innovative market outcomes. It is essential that the competitive market engine is fueled by high quality infra-marginal rents with minimum intervention. Arguably, it is a signature change of market liberalization to shift the risk away from customers to suppliers by allowing suppliers to earn infra-marginal rents in a competitive market as a matter of tradable rights. Any dilution of such tradable rights, such as by

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5 *See* Hung-po Chao, Peak Load Pricing and Capacity Planning with Demand and Supply Uncertainty, *Bell Journal of Economics,* Vol. 14, Issue 1 (1983); Hung-po Chao & Robert Wilson, Resource Adequacy and Market Power Mitigation via Option Contracts (Mar. 18, 2004), https://faculty-gsb.stanford.edu/wilson/PDF/Electricity%20Markets/Chao-Wilson,Resource%20Adequacy%20and%20Market%20Power%20Mitigation031804.pdf; Peter Cramton et al., Capacity Market Fundamentals, *Economics of Energy & Environmental Policy*, Vol. 2, No. 2 (2013). Note that with perfect competition, the capacity offers should converge to the Net CONE value, forming a rather flat supply curve. In that scenario, the infra-marginal rent would be essentially zero, and the efficiency losses caused by resource substitution effects could be small.

denying infra-marginal rents to suppliers that submit infra-marginal offers, is likely to eventually raise the costs and risks for customers in the long term.

16. The simplest and most direct way to counteract these adverse effects of resource substitution is to provide that all infra-marginal resource offers are paid their infra-marginal rents, even if they are denied a capacity commitment (due to commitment of the subsidized uneconomic resource). PJM's Extended RCO proposal does this, by paying infra-marginal resource offers that do not clear a payment equal to the difference between the clearing price and the resource's offer. That seller is not paid for the amount of its offer, which presumably reflects its net avoidable capacity costs, because it is not committing its resource as capacity. But the seller is paid for its infra-marginal rents, just like any other infra-marginal resource offer that helped set the clearing price. This result is comparable to what can happen today when a seller's resource clears the Base Residual Auction ("BRA"), but the seller then pays a substitute resource in the incremental auction to fulfill its capacity commitment. Such a seller should be willing to transfer the capacity commitment to someone else at the seller's BRA offer price, allowing the seller to keep the infra-marginal rent (i.e., the difference between its BRA offer and the BRA clearing price). By combining these two transactions into one transaction in the auction, I find that compensating "crowded-out" infra-marginal resources for the infra-marginal rents they would have earned absent commitment of the subsidized resource, is consistent with the fundamental market principles based on the tradable rights doctrine.

17. Paying these resources for their infra-marginal rents also preserves the correct price signals and incentives. Under competitive conditions, each capacity resource would be indifferent to whether it is paid its offer price for undertaking a capacity commitment, or paid nothing with no capacity commitment. By logical extension, the resource should also be indifferent whether it is paid the market price for undertaking a capacity commitment or paid the infra-marginal rent with no capacity commitment. The resource should be indifferent in that scenario, because it will not be better off or worse off financially as a result of the resource substitution to accommodate the sponsored resources. With these Extended RCO rules in place in a competitive market, resource owners would confront the same competitive forces to offer at their resource's true costs. For example, if the seller attempts to raise its offer price above the resource's true cost, it would risk being priced out of the market and lose its entire infra-marginal rent. Or, if a seller attempts to offer at a price below the resource's true cost, it would run the risk of suppressing the market clearing price or being cleared at a market price below its true cost and incurring a loss.[6] Compensating the substituted resources for their infra-marginal rents thus would solidify the incentive for resources to make truthful offers that reflect actual costs in a way that is consistent with the principles of efficient price formation and risk allocation.

6 Obviously, the possibility of gaming is sensitive to market conditions. In the presence of market power or collusion, for example, one cannot rule out the possibility that resources may be able to influence market outcomes and increase profits by making offers that deviate from their truthful costs.

F. Recovering Infra-Marginal Rent Payments from the Seller that Elects the RCO

18. Who should pay for the infra-marginal rents incurred by the substituted resources? If these charges (essentially designed to counteract dead-weight losses) are expected to be large enough to warrant adoption of the Extended RCO in the first place, then they should be allocated to the sellers of resources that elected the RCO. This honors the cost-causation principle, because that seller, given the choice to offer its resource at an economic price set by the MOPR, or commit an uneconomic resource via the RCO, chose the latter course. Commitment of that uneconomic resource displaces economic infra-marginal resources, and would (absent the corrective rule) deny that resource its infra-marginal rents, thus bringing about the resulting dead-weight loss. Moreover, these economic costs differ from the capacity commitment, because these costs are supposedly offset by the social benefits within the state that sponsors the subsidy programs. This can be illustrated by a simple example.

19. Suppose that the capacity market clears at a price of $100 per MW-day. A 100 MW resource "A" offered at $95 per MW-day and clears the market, but is substituted out due to commitment of a 100 MW sponsored resource "B." The infra-marginal rent for resource A equals ($100 - $95) per MW-day x 100 MW, i.e., $500 per day. Assume further that the true cost of capacity commitment for sponsored resource B is $110 per MW-day, which is higher than the market clearing price. For resource B to be viable at the market price after the cost allocation of $500 to resource A, it would need a subsidy in the amount of $15 per MW-day, which should be offset by the external benefits of resource B to the state. From the perspective of domestic divergence theory, if the subsidy reflects the social benefit of domestic resource, it should break even with the social cost at $15 = $10 + $5. In that case, allocating the economic cost to the seller that elected the RCO comports with both cost causation and "beneficiary pays" principles, and is reasonable.

20. This concludes my affidavit.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

Hung-po Chao, being first duly sworn, deposes and states that he is the Hung-po Chao referred to in the foregoing document entitled "Affidavit of Hung-po Chao, Ph.D on Behalf of PJM Interconnection, L.L.C.," that he has read the same and is familiar with the contents thereof, and that the facts set forth therein are true and correct to the best of his knowledge, information, and belief.

[signature]

Subscribed and sworn to before me, the undersigned notary public, this 1st day of October 2018.

Linda Spreeman

Notary Public

My Commission expires: November 17, 2019

COMMONWEALTH OF PENNSYLVANIA
NOTARIAL SEAL
Linda Spreeman, Notary Public
Lower Providence Twp., Montgomery County
My Commission Expires Nov. 17, 2019
MEMBER, PENNSYLVANIA ASSOCIATION OF NOTARIES

{W0171926.1}

Attachment D

Deadline (no later than)	Activity
150 days before RPM Auction	Specify whether Capacity Resource with Actionable Subsidy
120 days before RPM Auction	Submit request for resource-specific MOPR Floor Offer Price and/or Self-Supply Exemption
90 days before RPM Auction	IMM makes final determination of resource-specific MOPR Floor Offer Price and/or Self-Supply Exemption
65 days before RPM Auction	PJM makes final determination of resource-specific MOPR Floor Offer Price and/or Self-Supply Exemption
60 days before RPM Auction	Market Seller confirms MOPR Floor Offer Price and last day for PJM to disagree with Market Seller's designation of Capacity Resource with Actionable Subsidy
30 days before RPM Auction	Market Seller to notify PJM that it elects to forego the subsidy and not be subject to MOPR
30 days before BRA	Market Seller to (1) elect the Resource Carve-Out and (2) on an annual basis, specify UCAP value of the Carved Out Resource
20 days before BRA	PJM to post aggregate MWs of Carved Out Resources

CERTIFICATE OF SERVICE

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

Dated at Washington, DC, this 2nd day of October 2018.

/s/ Paul M. Flynn

Attorney for
PJM Interconnection, L.L.C.

The Challenges of Comparing PV's Success to Efficiency

Gabrielle Stebbins, Energy Futures Group
Chris Kramer, Energy Futures Group
Greg Leventis, Lawrence Berkeley National Laboratory

ABSTRACT

With increasing frequency, broad statements are being made that highlight the success of the solar photovoltaic (PV) market— often followed by questions on why the energy efficiency market hasn't seen similar meteoric growth. Some commenters conclude that efficiency needs to move away from programs and rebates and stand on its own two feet, like PV. But such statements are simply too broad to be supportable. Many energy efficiency submarkets have seen significant success - some greater than PV in terms of volume or market share. This is especially true for technologies involving one-for-one replacements, including lighting and appliances. And the PV market *has* received incentives and market interventions to drive growth, including tax credits that far exceed those available for efficiency projects both in size and usefulness. This paper illustrates the many differences between PV and a specific type of efficiency work that can be done within similar cost parameters (the whole-home retrofit) in hopes that future dialogue comparing these options will be more specific and grounded.

"Wow! Look at PV! What's Wrong With Efficiency?"

In recent years a growing number of voices in public policy discussions have raised questions as to why efficiency has not seen the same level of success as PV. States with leading PV deployment and a strong commitment to advancing energy policy such as Connecticut, New York and California have all seen significant growth in the PV market even as state incentives are reduced. All three of these states have also seen commentary suggesting that efficiency should become more self-sufficient, ultimately moving away from programs and rebates – "just like PV".

For example, in December of 2015, the Connecticut Green Bank stated support for an increase in a customer co-pay for energy efficiency work because "it is important to signal to the market that there is a transition to lower subsidies in order to provide it with an opportunity to grow. Given our experiences reducing incentives by over 70% and increasing demand for rooftop PV by over 2000 percent, the Green Bank stands ready to assist the Department of Energy and Environmental Protection, the Energy Efficiency Board, and the utilities to help with program design to scale-up the Home Energy Solutions program to deliver more savings with less subsidies." (Farnen 2015).

In New York, the Chair of Energy and Finance, who is also the Chair of the New York State Energy Research and Development Authority (NYSERDA) Board has commented on the success of the PV industry in transitioning away from rebates, while highlighting the goal for NYSERDA and utilities to become "market enablers", rather than the "market" itself: "When you're in the resource acquisition business, you become the market, and the market organizes itself around trying to get grants. We're restructuring programs at NYSERDA and at the utilities to do things so they are enablers of markets, rather than becoming the market...NY Sun is a good example. The industry will be off of all public support well within 10 years." (Kaufmann 2015).

This is further characterized in the New York State Public Service Commission's 2015 Order Adopting Regulatory Policy Framework and Implementation Plan: "There are, however, distinct disadvantages to an approach that relies solely on rebates. A rebate program can have the unintended effect of displacing markets and inhibiting market transformation. Where a program that subsidizes well-established technologies and practices is maintained indefinitely, market activity outside of the program is at a disadvantage...In contrast, a successful market transformation program can leverage far more customer investment than a direct rebate program can. The end goal of a market transformation program for any particular measure is to eliminate further need for customer-funded subsidies of that measure." (Zibelman, Acampora and Sayre 2015)

In California there has also been rhetoric describing the successful weaning of the PV industry off of rebates – and how efficiency programs have done poorly in comparison: "The recent success and rapid growth of PV energy provides an instructive example of such innovation. It's a real-time example of the power of market forces to reward business models that work for customers and industry while being held accountable to results. As the California PV Initiative rebate program trended from a subsidy of nearly 50 percent to zero, a strong industry, driven by billions in private capital, has emerged in its wake. Costs have plummeted as financial and technology innovations have delivered solutions to meet customer demand, resulting in a huge influx of private investment and innovation in technology, finance and business models. By contrast, the energy efficiency industry has been conducting a grand experiment for the past 40 years to prove the theory that top-down programs can "transform markets". At this point, we have proven rather conclusively that the program-centric approach to energy efficiency does not appear to benefit from economies of scale found in competitive markets." (Golden 2014)

Certainly, the goal of achieving market transformation for efficiency is one we can all agree upon, and many of the points raised by the commenters above are valid. The level of activity that would be required to make a significant dent in installing comprehensive home retrofits is not occurring, and the available funding resources are not near the required cost to upgrade and retrofit well over 100 million existing buildings in the United States (Granade et al. 2009; Goldman et al. 2011). And we *have* seen a considerable reduction in some areas of PV incentives and the market has continued to grow.

For example, between 2012 and 2015, Connecticut saw a reduction of their PV incentive from $2.45 per Watt (up to the first 5 kiloWatt) and $1.25/W (for the next additional 5 kW), to a 2015 offering of $0.064/kWh up to 10 kW in size (Shaw, Drake-McLaughlin, and Khawaja 2016). Meanwhile, in New York, the NY-Sun Incentive Program establishes incentives based on a Megawatt (MW) Block design that assigns MW targets to specific regions of the State. Incentives are established for each MW block and are awarded to applications based on the block in effect at the time of submission. When a MW Block is fully subscribed, the next block, with decreased incentives, goes into effect (NYSERDA 2016). California also utilizes an incentive structure where the rebates automatically decline in "steps" based on the volume of PV MWs with confirmed project reservations (California PV Initiative 2016). It's clear that state incentives for PV have been decreasing. Is it also accurate that PV is seeing greater success than efficiency? Not necessarily.

Is PV Actually More Successful than Efficiency?

When we talk about PV in a residential context we are talking about a single technology whose application is generally well-understood. We install panels on the roof or in the yard that turn sunlight into electricity. In contrast "efficiency" can mean many different things, from the installation of specific measures (such as an efficient appliance) to a comprehensive whole-home retrofit. And some measures may be installed individually or within a comprehensive approach that combines multiple technologies. Trying to answer questions about the relative success of PV compared with efficiency requires more precise definitions— are we talking about single technologies with one-for-one replacements, such as lighting and appliances, or are we talking about complex, multi-faceted projects that address multiple technologies and end-uses?

We *have* seen program-centric models for discrete, singular efficiency measures result in a transformed marketplace. For example, witness the change in market penetration according to shipping data provided by the National Electrical Manufacturer's Association in Figure 1. In 2011, incandescent products were nearly 70% of shipped a-line lighting, but by 2015 these products represented less than 10% of shipments:

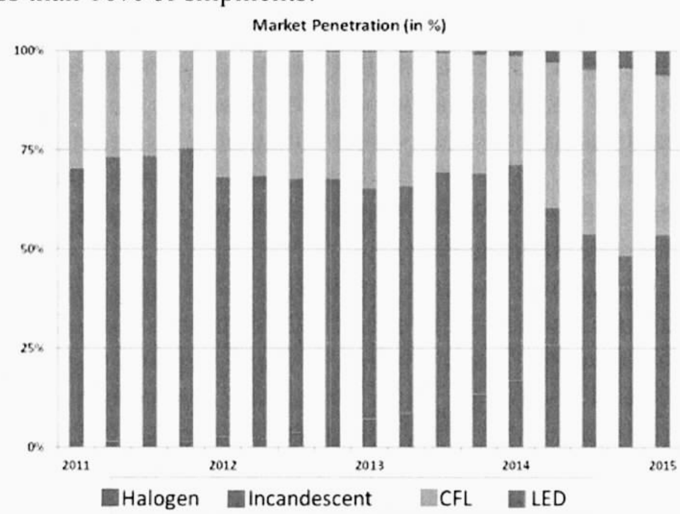

Figure 1. Shipping data for lamp indices, a-line.
Source: NEMA 2-15.

Comparing the PV and the lighting markets shows that both have seen similar trends in cost curves, opening the door for both more profit and more market interest (EIA 2014).

Clothes washers, furnaces and air conditioners have seen considerable support through efficiency programs and are achieving significant market transformation. The ENERGY STAR® Unit Shipment and Market Penetration Report Calendar Year 2014 Summary reports the following market penetration rates for these technologies: 69% for clothes washers; 24% for residential gas furnaces; 15% for residential oil furnaces; and 50% for room air conditioners

(Environmental Protection Agency, 2014). Further, the 2014 national market share for ENERGY STAR® Certified New Homes was reported to be 11.8% (EPA 2014).

However, if we take "efficiency" to mean a comprehensive, "whole-home" energy upgrade project that addresses multiple fuels— such as would be promoted through Home Performance with ENERGY STAR®— then the kind of growth that has been praised in the PV market has indeed been elusive to date. However, there are important reasons why this is the case, and simply reducing market support to this type of effort is unlikely to lead to the same kind of market changes that have been seen with PV.

So How Does the Whole-Home Retrofit Market Compare to the PV Market?

So how does the whole-home retrofit market compare to the PV market? While PV has seen growth, do the data really show that PV has seen greater market penetration than whole-home retrofits? And, is it accurate to portray PV as not receiving market interventions such as incentives and rebates? Let's try to find out.

First, it is critical to recognize the difference between market growth and market penetration. Assessing the PV market penetration based on estimated numbers of residential installations, the Solar Energy Industry Association recently found that 135,000 homes and businesses had PV installed during the first half of 2015 (SEIA/GTM 2015). Compare this to the finding that in 2009, 861,000 homes had insulation[1] professionally installed (DOE 2012 Table 2.6.3). Extrapolating the 135,000 PV installations over the entire 2015 calendar year would result in 270,000 PV installations for 2015. It is likely that the actual number is larger, but even a comparison of 270,000 PV installations (homes and businesses) to 861,000 homes (excluding businesses) shows that insulation is seeing greater market penetration if based upon number of installs. Additionally, with PV we are "measuring" an entire market that started very small just a few years ago, whereas with whole-home retrofits we are trying to increase a market that has been seeing growth for several decades.

Regarding market growth from the perspective of revenue, AEE finds that solar revenue in 2015 in the United States is estimated to reach $22.6 billion, while the efficiency lighting market (for an "apples-to-apples" comparison of a single measure to another single measure) is estimated to reach $24.6 billion (AEE 2016). The closest comparison to a "whole home retrofit" is the building envelope market which is estimated to reach $14.1 billion. Clearly, we are seeing significant market growth in PV, but that does not necessarily equate to market penetration, nor to the tag-along assumption that the efficiency market is not succeeding, and therefore that this market should be weaned off program support.

This leads to another important clarification. The statements quoted earlier infer that PV has grown predominantly through financing and hasn't seen the same sort of market interventions as efficiency. This is simply untrue. Certainly, as shown above, we have seen various states reduce state rebates for PV, but it must be recognized that Renewable Portfolio Standards, a transferrable 30% federal investment tax credit, and net-metering policies are all forms of market interventions that have supported and continue to support the PV market.

[1] We have chosen to reference insulation installations as the closest proxy to a "whole-home retrofit" available as compared to other efficiency measures based on the previous explanation of the definition of "efficiency" for this paper.

How Do the Technologies and Markets Differ?

Efficiency can never the less learn from the development of the PV market. Yet, to adequately identify what those lessons may be, we must first identify where the two technology options differ to ensure that lessons across the sectors are actually transferable. Table 1 shows a number of significant differences ranging from economics to human behavior to technology.

Table 1. Comparison of PV to efficiency

Category	PV	"Efficiency"	Outcome
Economics: Overall Project Cost	~$20,000-$25,000	~$8,000-15,000[1]	PV businesses have a greater margin to work with than efficiency businesses to meet opportunity costs and make profit, which increases investor interest
Economics: Federal Tax Credit	Up to 30% ($6,000 - $8,000)	Tax credits (typically in the range of ~$300-$500) available per individual efficiency unit but not comprehensive retrofits	Transferability has led to PV attracting significant interest by tax equity investors
Economics: Soft Cost Reductions	Over 5 years: PV industry has seen multiple soft cost improvements: tax certainty, moving from permitting to "registration" processes, simplified meter installs, etc.	Over 40 years: efficiency industry has decreased labor time by streamlining software requirements (e.g. reducing inputs); Hardware has improved (blower door, duct blaster); Cost reductions have occurred (infrared cameras), etc.	Both technologies have made multiple software and hardware cost reductions. As PV is a newer industry, it may be likely that there are more soft cost reduction opportunities remaining for PV as compared to efficiency
Economics: Bill Visibility	PV is an easy relationship to electricity – one technology shown on one bill	Efficiency savings may occur across multiple bills: electricity, heating, water	More difficult to see the immediate financial value of efficiency
Economics: Financing	PV has seen considerable Third-Party-Ownership (TPO) financing models	Federal tax credits for efficiency are not transferable, and financing mechanisms such as PACE have not yet appeared to result in the same market response as TPO	Some cite TPO as a primary driver to PV growth (Bollinger and Holt 2015). If this is accurate, then efficiency faces large hurdles to obtain the same level of growth without TPO
Human Behavior: Metering	PV can show it is producing energy and making money	Efficiency benefits are counter-factual: generally, they do not prove that it is saving money and energy[2]	Customers feel more confident in investing in a product that shows its output in an easy, numerical way

[1] This range of comprehensive retrofit costs comes from Vermont.
[2] The authors recognize that there are now some connected smart devices and controls capable of offering more "real-time" visible proof of energy savings. However, this is not yet mainstream and therefore the potential impact to the market and customer experience is not yet understood or comparable to the visibility of PV production metering.

Category	PV	"Efficiency"	Outcome
Human Behavior: Visibility	PV is visible	Efficiency is invisible	For customers who choose PV because it may be interpreted as a status symbol, visibility matters. For EE, building labeling (which is not yet common) could help but is not the same as a shiny piece of silicon and metal
Technology: Plug and Play	PV is relatively easy to install and complete and in many instances can be relatively "cookie cutter"	Efficiency requires diagnostic analyses for each project, incorporating multiple steps with a variety of technological and financial decision-points required by the customer throughout the project process[1]	Customer may find PV more understandable and may be more easily confused and deterred by efficiency's complications. Additionally, the various tasks involved in a whole-home retrofit (e.g. air sealing, insulation, appliance replacements) frequently requires different contractors to do different parts of the work, thereby increasing overall project complexity
Technology: Intrusiveness	PV is relatively unobtrusive with installers climbing on a roof or installing a stand-alone system in a backyard	Whole home retrofits require workers to be in and out of ones' home for multiple days	Many customers find having contractors and on-going construction in their homes while they live in them to be, at the very least, inconvenient. The alternative of moving out during the retrofit work is also, at minimum, an inconvenience
Technology: Work Required	PV requires very little effort from the customer	Efficiency can require customer labor to empty out the attic and basement	Customer may not want to undertake the effort needed to prepare in advance for efficiency[2]

Customer Perspective

It appears that there are relatively few similarities between a whole-home retrofit (which is only one of many different types of "efficiency programs") and the installation of PV. Ultimately, as the Lawrence Berkeley National Laboratory's human behavioral research has pointed out (Fuller et al. 2010), programs must sell something that people want. Of the two most often cited reasons why customers choose to do energy upgrades (save money and "do the right thing"), PV has distinct advantages over efficiency.

[1] While some programs have sought to streamline and therefore simplify this experience, this does not appear to be the "norm" for whole-home retrofits throughout the United States.

[2] Comparing whole-home retrofit work to basement waterproofing provides additional insight regarding the "work required" category. Basement waterproofing does not see support from federal and state programs and yet has seen the growth of successful, mature waterproofing businesses that provide a "one and done" experience offering financing during the first customer interaction and closing the deal within a few hours. Like efficiency, basement waterproofing often requires the homeowner to empty storage areas so it could be assumed that this would act as a deterrent. However, while emptying out a basement may be a hassle, having all basement items be routinely flooded is even more of a hassle. Ultimately, one level of inconvenience may outweigh another. While basement waterproofing may be similar to whole-home retrofits in the level of "work required" by the homeowner, there is an additional motivation for the homeowner to undergo the hassle of emptying out the basement due to the vivid customer experience of having to regularly deal with a flooded basement. Another point in waterproofing's favor? A flooded basement is far more visible than air leakages and drafts.

PV in a Nutshell

From a customer perspective, PV provides homeowners with the ability to watch the meter go backwards and also realize the financial investment on their utility bill. PV is highly visible and easy-to-install with a clear, single call-to-action that, once done, is completed for 20-25 years. PV requires little physical labor for the customer, and does not ask the customer to make any decisions between "this energy upgrade or that". For customers to whom it matters, a PV panel shows everyone that they made this "green" investment.

Efficiency in a Nutshell

From a customer perspective, efficiency is invisible, with savings spread across multiple energy bills and requiring numerous decisions from the homeowner as to which efficiency measures to undertake. Compared to PV, efficiency is an on-going continuum like many building maintenance projects, and often the benefits are less measureable (for example, improved comfort) than those associated with PV installations. Measuring the effectiveness of the efficiency upgrades requires compiling the savings across several utility bills and perhaps an unregulated source such as cord wood or pellets, thereby making the savings less direct and clear for the customer as compared to PV production on one electric bill. Granted, over the last few years more cities and realty groups are including HERs ratings in housing information at point of sale, but this is relatively new and not as visible as a new PV array perched on a roof. Perhaps most importantly, whole-home retrofits can require significant labor on behalf of the homeowner to empty out one's attic and basement or to move out entirely. Case in point: a trial in Great Britain found that customers were three times more likely to do insulation projects when the work was offered with attic-clearing services as part of the scope (Gray and Ross 2012).

Financing and Third Party Ownership (TPO)

Often when the argument is made that energy efficiency should seek to emulate PV market trends, a key focus is on the central role that financing, and in particular TPO has played within the PV industry. Just as there are key differences in these technologies and markets, however, there are also important distinctions that should be recognized in terms of the role of financing within each industry.

One consideration regards the basic purpose of financing. Typically, customers will choose to take out financing only if they have either a need or a strong desire to complete a project that they cannot otherwise afford. Where their motivation is less strong, customers often will choose to forgo a project rather than take out debt to enable it moving forward.

In the residential PV market, recent trends indicate a strong desire among some segments of the population to acquire PV panels (Clover 2015). For these customers, financing may offer a solution to allow them to take on a project that they already are very interested in doing. By contrast, there is less clarity within the energy efficiency market as to whether there is a growing demand for comprehensive residential retrofits, and in particular for less visible measures such as air sealing and insulation. If customer motivation is not independently growing increasingly strong in this market, then it is much less likely that offering financing will facilitate rapid growth on its own.

As previously noted, growth rates and market penetration are vastly different metrics. As such, it may be worth noting that even if financing has facilitated *growth* within the PV market among those customers who are independently motivated to complete PV projects, it is much less clear whether that growth will be limited by the size of the sub-segment that is independently motivated in this way. If this turns out to be the case, then just as in the energy efficiency market, the impact of financing in the PV market may be limited by whether external drivers can further increase demand.

One additional way in which financing is sometimes used to encourage energy projects is by spreading repayments out sufficiently to be fully covered or exceeded by energy savings. It is worth noting, however, that this type of arrangement may be more attractive in the PV realm than the efficiency industry, given that PV output can be metered, giving customers more confidence that energy savings projections will be realized.

Indeed, in the energy efficiency industry, realization rates are often well below 100 percent (West Hill Energy and Computing 2013; Reeves et al. 2014) which customers may intuitively sense given the challenges in measuring savings directly. While some pilot efforts are being made to address this issue in the efficiency space via savings guarantees over a portfolio of homes (which may be less risky collectively than banking on savings projections for a single home) results of these efforts thus far have not gone to scale. Unless and until the confidence barrier can be overcome in the energy efficiency sector, cash-flow-positive financing arrangements may remain much less powerful in this market than in the PV field.

Finally, it should be pointed out that the growth of financing models within the PV industry has largely been spurred by the interaction of financing and federal tax credits via TPO models (Bollinger and Holt 2015). Both leasing arrangements and power purchase agreements allow third-party investors to take advantage of these tax credits in the PV market, which has provided an attractive business model that has brought in significant investment to grow the PV industry to scale. No comparable tax credits currently exist in the energy efficiency space, nor is it clear whether the nature of certain key energy efficiency measures such as air sealing and insulation would allow for a TPO model that could facilitate the transfer of tax credits even were they to become available.

For all of these reasons, while financing is likely to continue to play an important role in the energy efficiency industry, it is oversimplified to suggest that the key to growing the industry to scale is to rapidly ramp up financing models and ramp down programs.

Additionally, according to Lawrence Berkeley National Laboratories' Mark Bollinger, from a policy design perspective, "be careful what you wish for". While PV hard and soft costs have greatly reduced, it is not all that clear that these reductions have reached the end-customer (M. Bollinger, research scientist, Lawrence Berkeley National Laboratory, pers. comm., March 4, 2016).

Limitations and Qualifications

Various reviewers of this paper have asked the authors why the data comparisons are not a clear, simple "one-to-one" analysis. For example, using the same reference years when comparing solar PV installations to whole-home retrofits; or comparing market revenue for PV installations to whole-home retrofits (as compared to just building envelope work – which may not include appliances and heating, ventilation and air conditioning (HVAC) efficiency improvements). The authors recognize that this type of comparison would be preferable to what is provided here, and will continue to work towards that. However, at the time of the writing of this paper, the data sets referenced are the resources available to the authors with permission. One data challenge results from the fact that much of the available efficiency analyses focus on a discrete, singular measure rather than the more comprehensive, "whole-home retrofit" measure. For the purposes of this paper, our points remain valid: broad sweeping statements that question the success of efficiency as compared to PV are not only inaccurate but also limit the potential for helpful "lessons learned" across the PV and efficiency markets due to their lack of specificity.

Conclusion: Where To From Here?

It is clear that overarching statements that highlight the success of the PV industry to the efficiency industry and then question the success of the efficiency industry and efficiency programs in a broad sweeping approach, is problematic. First, it's inaccurate: energy efficiency submarkets have seen significant success – many greater than PV. Second, even the most difficult energy efficiency submarket, the whole home retrofit as defined in this paper, sees success. Third, the PV market *has* received incentives and market interventions to drive growth.

Are there potentially "lessons to be transferred" from the PV market to the market serving whole-home retrofits? It is likely. But in order for those lessons to be truly illustrative and transferable, we must first identify the many differences between these markets. Only then can we rightly compare markets and identify transferable lessons from PV to efficiency. For example, identifying how to bring the "cache" of efficiency closer to that of PV, and making flexible tax credits available for efficiency could potentially make a large difference for the whole-home retrofit market.

Many energy experts would like to see a vast increase in the number of whole-home retrofits across the United States. Certainly, forty years of programs have not yet achieved market transformation for this category of efficiency work. However, overarching statements that look to the success of the PV industry to identify what efficiency can do differently to achieve market transformation are only helpful to the degree that the comparison recognizes the economic, human behavior and technological differences between these two customer-facing energy opportunities.

As PV policies, particularly net-metering, continue to evolve, and as whole-home retrofits, hopefully, become more visible and quantifiable from a customer perspective through mechanisms such as HERs and bill guarantees, we may see a shifting of the challenges and opportunities for PV as compared to whole-home retrofits. In the meantime, opportunities to reduce some of the hurdles the whole-home retrofit market faces may be identified by comparing the differences between PV and comprehensive retrofits, as provided in Table One.

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OHIO POWER COMPANY'S RESPONSE TO
THE OFFICE OF THE OHIO CONSUMERS' COUNSEL'S
DISCOVERY REQUEST
PUCO CASE NO. 18-501-EL-FOR 18-1392-EL-RDR AND 18-1393-EL-ATA
TWELFTH SET

INTERROGATORY

OCC-INT-12-159 Page 8 of 38 of Exhibit SB/BL-1 states: "However, an important point is that the results of even the most carefully-constructed economic impact analysis represent only the order of magnitude of the true impacts." Explain what is meant by "order of magnitude" in this context.

RESPONSE

The *meaning is that the results of any RIMS II analysis are rough approximations of the true* impacts. The primary reason for this is that the model is based on typical relationships between changes in the demand for a particular good or service faced by a firm and the changes in the derived demands faced by the suppliers to that firm as it meets its own demand change. To the extent that the direct firm (the solar plants in this case) purchases goods and services in a pattern different from a typical similar firm, the realized impacts will differ from the predicted impacts.

One example of how the firm's demands on suppliers may be atypical is the case of a chain retailer versus a locally-owned retailer. In order to maximize efficiency, most chains centralize their suppliers of inventory, supplies and equipment, and business services. This means that most of the sales revenue earned by a chain store leaves the local economy immediately and has zero local impact. In contrast, locally-owned, locally-serving retailers tend to deal much more frequently with local suppliers and often procure their business services locally as well. In other words, the indirect and total impacts of the locally-owned firms are greater than those of chain retailers, and greater than would be predicted by the RIMS II multipliers, which are based on the purchase patterns of both chain and locally-owned retailers. Civic Economics in partnership with the American Booksellers Association measures the impact of locally-owned businesses in communities across the country.[1] The results of the ten Civic Economics studies on locally-owned versus chain retailers are that locally-owned retailers trap 48 cents of each sales dollar while chain retailers trap less than 14 cents. Individual communities' results varied from 39 cents to 66 cents per sales dollar. Again, these are differences in the indirect impacts of locally-owned versus chain retailers.

Various approaches can be employed to improve the accuracy of an economic impact analysis. First, the model works best when it is used to analyze changes that are small relative to the economy being analyzed. This is because the model is based on existing input-output relationships in the subject economy. If a major new manufacturing plant is developed in a relatively small region, it could be expected that suppliers to the plant would also relocate or expand in the immediate area, resulting in material changes in the structure of the local economy and in input-output relationships. This implies that an economic impact analysis of the plant using standard techniques would be invalid. However, the construction and operation of these two solar installations are small relative to the Ohio economy.

PENGAD 800-631-6989
EXHIBIT
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**OHIO POWER COMPANY'S RESPONSE TO
THE OFFICE OF THE OHIO CONSUMERS' COUNSEL'S
DISCOVERY REQUEST
PUCO CASE NO. 18-501-EL-FOR 18-1392-EL-RDR AND 18-1393-EL-ATA
TWELFTH SET**

A second method to minimize the inaccuracy of economic impact analyses is to use the bill-of-goods approach.[2] This approach was used in the solar plant study. Rather than applying the general construction multiplier to the total construction cost and the general electric generation multiplier to the total value of output, the specific purchases made within Ohio in the construction and operating budgets are related to the multipliers relevant to the industry supplying those goods and services.

Finally, it is critical that the input data be as accurate as possible. We emphasized to AEP that the accuracy of the budgeting data be as accurate as possible and worked closely with AEP staff as they acquired budgeting data from the developers.

[1] See http://www.civiceconomics.com/indie-impact.html.
[2] See Bureau of Economic Analysis (2012). *RIMS II: An essential tool for regional developers and planners,* pp. 5-5 – 5-8.

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Akron Beacon Journal/Ohio.com

How much has the opioid crisis cost Ohio?

Posted May 25, 2018 at 12:09 PM

Even before the opioid crisis peaked here in 2016, Ohio was already spending about the same on opioid dependency statewide as it did kindergarten through high school education, according to a recently released study.

The enormous price tag in 2015 of opioid dependency in the state was somewhere between $6.6 billion and $8.8 billion. During the same time, the state spent about $8.2 billion on public education, according to the study released by Ohio State University's C. William Swank Program in Rural-Urban Policy.

Your Voice Ohio, a news collaborative, highlighted the study last week as the state's behavioral health, addiction and rehabilitation workers are preparing to host the ninth annual opiate conference in Columbus next month. The two-day educational event is expected to draw 1,200 people.

The study, "Taking Measure of Ohio's Opioid Crisis," aims to help policymakers make better decisions by evaluating the crisis.

Among other things, the study zeroed in on the costs of opioid addiction across four categories: Health care and treatment, criminal justice, lost productivity among opioid abusers, and lost productivity following an overdose death.

In 2015 — the most recent numbers used for this part of the study — those costs added up to between $500 and $999 for every person in Summit, Portage and Wayne counties, regardless of whether they used drugs themselves.

The costs in Stark and Medina were lower, somewhere between $0 and $499 per person, the study said. But costs skyrocketed in the southwest part of Ohio, averaging more than $1,000 per capita in an area stretching from Dayton and Cincinnati east to Lawrence County, Ohio's most southern county, which borders West Virginia.

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Krozer

Because costs were so extraordinary in southwest Ohio, the study said "state efforts to reduce current and future opioid abuse should likely focus on this area of the state."

It is not clear, however, if the arrival of fentanyl and carfentanil — which hit Summit County in 2016, a year after the costs were calculated in the study — has changed which parts of the state have been hit hardest by the evolving opioid crisis.

To read the full study, go to: https://bit.ly/2Lp8WvT

Overdoses among Summit County residents ticked down May 18 through Thursday.

A weekly report by public health officials shows that 20 residents sought hospital emergency room help for an overdose during that time.

Nearly 95 percent of those were white, a little more than half were women and those seeking treatment had an average age of 41.

That works out to less than three overdoses per day, compared to 2016 when it was common for 19 people per day to show up in area hospital emergency rooms after overdosing.

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