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 No. ER18-1314
PJM Interconnection, L.L.C.	)	Docket No. EL18-178 (Consolidated)

COMPLIANCE FILING CONCERNING THE MINIMUM OFFER PRICE RULE, REQUEST FOR WAIVER OF RPM AUCTION DEADLINES, AND REQUEST FOR AN EXTENDED COMMENT PERIOD OF AT LEAST 35 DAYS

March 18, 2020

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COMPLIANCE FILING CONCERNING THE MINIMUM OFFER PRICE RULE, REQUEST FOR WAIVER OF RPM AUCTION DEADLINES, AND REQUEST FOR AN EXTENDED COMMENT PERIOD OF AT LEAST 35 DAYS

In compliance with the December 19, 2019 Order Establishing a Just and Reasonable Rate of the Federal Energy Regulatory Commission ("Commission" or "FERC") in the above referenced proceedings,[1] PJM Interconnection, L.L.C. ("PJM") hereby submits revisions to the PJM Open Access Transmission Tariff ("Tariff") to modify the application of the Minimum Offer Price Rule ("MOPR") to address State Subsidies and their impact in the PJM capacity market, known as the Reliability Pricing Model ("RPM").[2] This filing is strictly designed to comply with the Commission's December 19 Order with specific tariff language included to effectuate the Commission's order.[3]

By this filing, PJM addresses the Commission's compliance directives and incorporates the modified MOPR design elements into the capacity market rules in the Tariff. As further explained below, where certain elements of the Commission's December 19 Order required additional details to support the design and application of the modified MOPR, PJM has used its best efforts to add these additional detailed elements to comply with the overarching goal of the December 19 Order. To provide market certainty, PJM will await Commission action on this filing before implementing the modified MOPR in the next Base Residual Auction ("BRA").

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1 *Calpine Corp. v. PJM Interconnection, L.L.C.*, 169 FERC ¶ 61,239 (2019) ("December 19 Order").

2 For the purpose of this filing, capitalized terms not defined herein shall have the meaning as contained in the Tariff, Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. ("Operating Agreement"), or the Reliability Assurance Agreement Among Load Serving Entities in the PJM Region ("RAA").

3 Many parties, including PJM, have sought rehearing and clarification of various provisions in the December 19 Order. PJM respectfully requests prompt action on those rehearing and clarification requests to reduce market uncertainty.

As directed by the December 19 Order, PJM is also providing a timetable for conducting the BRA for the 2022/2023 Delivery Year, as well as the BRAs for the following three Delivery Years. As necessitated by this timetable and to allow PJM to conduct the upcoming RPM Auctions on an orderly, but compressed, schedule following Commission action on this compliance filing, PJM requests waiver of its Tariff provisions that prescribed set dates or timelines for conducting pre-auction activities. Those issues are further addressed and detailed in Section IV of, and Attachment A to, this Transmittal Letter.

PJM also respectfully requests that the Commission establish a minimum comment period of at least 35 days (i.e., no sooner than April 22, 2020). Such an extension is appropriate given the volume of this filing and current circumstances. This will afford Market Participants sufficient time to review and comment on the proposed changes, which is necessary given the relative importance of this filing to PJM's capacity market.

I. BACKGROUND

On June 29, 2018, the Commission found that PJM's existing MOPR does not result in efficient market outcomes due to resources receiving out-of-market payments.[4] As a result, the Commission found PJM's existing MOPR rules to be unjust and unreasonable.[5] The December 19 Order established a replacement rate, providing parameters for addressing state subsidies in PJM's capacity market by extending the MOPR to cover not only certain new natural gas-fired generators, but also resources

[4] *Calpine Corp. v. PJM Interconnection, L.L.C.*, 163 FERC ¶ 61,236, at P 2 (June 29, 2018) ("June 29 Order").

[5] June 29 Order at P 6.

receiving out-of-market support through state subsidies.[6] In short, the December 19 Order directed PJM to extend application of the MOPR to all Capacity Resources receiving or entitled to receive a State Subsidy, regardless of resource type,[7] unless such resource qualifies for one of the exemptions set forth in the December 19 Order.[8] The December 19 Order also included a competitive exemption through which Capacity Market Sellers may elect to avoid being subjected to the modified MOPR by committing to forego any State Subsidies for the relevant Delivery Year.[9] Finally, the December 19 Order affirmed PJM's continued use of a resource-specific exception[10] that allows Capacity Market Sellers to demonstrate that the costs of their resources are less than the applicable default MOPR floor price and thus re-set the resource's applicable MOPR floor price down to a level that represents the resource's actual costs (excluding the impact of any State Subsidies).

II. STAKEHOLDER PROCESS

In an effort to allow all stakeholders to provide feedback to PJM prior to this compliance filing and to minimize the number of issues presented to the Commission to resolve on compliance, PJM held nine stakeholder meetings at which PJM's intended compliance with this order was discussed, including four special meetings of its Markets Implementation Committee dedicated solely to this topic. Each of the meetings was accompanied with detailed slide presentations and a description of specific elements to be

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6 The Commission did not adopt the resource-specific Fixed Resource Requirement ("FRR") Alternative it proposed in its June 29 Order.

7 December 19 Order at PP 8, 9 ("PJM must extend the MOPR to apply to all resource types.").

8 December 19 Order at P 9.

9 December 19 Order at P 2.

10 While the December 19 Order referred to the unit-specific exception, this filing uses the term "resource-specific" to clarify that the exception is available for all Capacity Resources because "resource" better encapsulates Energy Efficiency Resources and Demand Resources.

included in tariff language. In addition, stakeholders have availed themselves of opportunities to discuss their views with PJM staff and to send correspondence directly to the PJM Board. As a result, these issues have been the subject of rigorous review and consideration of varying stakeholder interests within the time limitations allotted by the Commission for the submission of this compliance filing.

Moreover, PJM has met with representatives of the state commissions in its footprint on a number of occasions and testified before state commissions and state legislatures throughout its footprint as to the details and potential impacts of the December 19 Order. The Organization of PJM States ("OPSI"), among others, has informed PJM and its Board of its views on a number of the subjects of this compliance filing (most notably the proposed timing of the next auction).

PJM has heard and thoroughly considered the views of all stakeholder and representatives of states and, through this compliance filing, has attempted to balance all of the competing views on these various issues into a proposal (set forth below) which is designed to meet the Commission's December 19 Order's directives while also ensuring orderly and timely capacity auctions going forward.

III. SATISFACTION OF THE COMPLIANCE REQUIREMENTS OF THE DECEMBER 19 ORDER

In compliance with the Commission's December 19 Order, PJM submits the following revisions to the capacity market rules in its Tariff.

A. In Compliance with the December 19 Order, PJM Is Extending the Application of the MOPR to State-Subsidized Resources, While Retaining MOPR Application to New Combustion Turbine and Combined Cycle Natural Gas Resources.

1. Commission Directive

The December 19 Order directed PJM to extend application of the MOPR to all resources receiving or entitled to receive a State Subsidy, regardless of resource type.[11] However, such resources are not subject to the MOPR to the extent they qualify for "one of the exemptions" established by the December 19 Order,[12] i.e., any of the four[13] categorical exemptions, the resource-specific exception, or the competitive exemption for foregoing receipt of any State Subsidy. In addition, the December 19 Order "clarif[ied] that the MOPR will continue to apply to new natural gas-fired combustion turbine and combined cycle resources," because "new natural gas-fired resources remain able to suppress capacity prices."[14] As with the current MOPR, any resource whose Sell Offer is limited by the MOPR may use the default MOPR Floor Offer Prices or seek a resource-specific exception under which its floor offer price will be set based on the resource's actual costs.[15]

2. PJM Compliance Language

PJM is complying with this broad directive by revising the MOPR provisions to apply to any Capacity Resource that receives or is entitled to receive State Subsidies (i.e.,

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11 December 19 Order at PP 8, 9 ("PJM must extend the MOPR to apply to all resource types.").

12 December 19 Order at P 9.

13 While the December 19 Order combined the exemption for Demand Resource, Energy Efficiency Resources, and Capacity Storage Resources, PJM proposes to separate out Capacity Storage Resources as a separate categorical exemption given the distinctions with Demand Resources and Energy Efficiency Resources.

14 December 19 Order at P 42.

15 *See* December 19 Order at P 214.

"Capacity Resources with State Subsidy"), while continuing to apply the MOPR to new natural gas-fired combustion turbine ("CT") and combined cycle ("CC") resources.[16] PJM generally defines a "Capacity Resource with State Subsidy" as any Capacity Resource for which the relevant Capacity Market Seller receives or is entitled to receive a State Subsidy.[17] The proposed Tariff language also provides that a Capacity Market Seller is "entitled to" a State Subsidy if it has a legal right or legal claim to the subsidy, regardless of whether the Capacity Market Seller has actually received the subsidy.[18]

PJM is not modifying the basic structure of the MOPR to comply with the December 19 Order. As currently applied to CT and CC resources, the MOPR Floor Offer Price generally establishes the lowest price the Capacity Market Seller of a Capacity Resource with State Subsidy may offer, while the Capacity Market Seller Offer Cap generally continues to establish the highest price. Further, as before, Capacity

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16 Unlike the current MOPR provisions that effectively apply only to natural gas-fired generation resources by setting the MOPR floor prices at zero for nuclear, coal, Integrated Gasification Combined Cycle, hydroelectric, wind, and solar resources, PJM is affirmatively applying the MOPR provisions to all CTs and CCs that have not cleared an RPM Auction (i.e., new CTs and CCs) and to Capacity Resources with State Subsidy based on the Commission's directive in the December 19 Order. *See id.*, at P 42. In addition, even though the Commission accepted the application of MOPR to natural gas-fired resources across the entire regional transmission organization ("RTO") and not only in constrained Locational Deliverability Areas ("LDA") in Docket No. ER13-535, the current MOPR rules apply only to resources in constrained LDAs. *See* proposed Tariff, Attachment DD, section 5.14(h)(4)(B)(ii). Consistent with the directives in the December 19 Order to expand the scope of the MOPR, PJM is proposing to apply the MOPR to new CTs and CCs located throughout the PJM Region.

17 Proposed Tariff, Definitions C-D. There are some additional caveats on this term, which are discussed below.

18 Resources included in an FRR Capacity Plan are not considered to be Capacity Resources with State Subsidy, nor would revenues received through inclusion in an FRR Capacity Plan be considered a State Subsidy. Rather, that term applies only to resources that participate in RPM. Accordingly, a resource that was in an FRR Capacity Plan one year and participates in an RPM Auction the next year would not be considered a Capacity Resources with State Subsidy solely due to such participation. However, as discussed below, the resource may otherwise be deemed a Capacity Resource with State Subsidy if, for example, the Capacity Resource previously accepted a State Subsidy before being included in an FRR Capacity Plan and has not cleared an RPM Auction since such State Subsidy terminated. *See infra* Section III.B.2.c.

Market Sellers of a Capacity Resource with State Subsidy will be able to offer at the default or resource-specific MOPR Floor Offer Price.[19]

The only exception to this general rule, other than when a Capacity Market Seller elects the competitive exemption, is when a Capacity Market Seller submits a Sell Offer for commercially aggregated resources where one or more resources that constitute such offer is eligible for a State Subsidy. In those cases, it is reasonable to allow a Capacity Market Seller to submit a Sell Offer that is equal to the time and MW-weighted average of the aggregated resources.[20] For instance, if a state subsidized solar resource (summer-only) is commercially aggregated with a state subsidized wind resource (winter-only), the Capacity Market Seller of such aggregated resources can submit a Sell Offer that is no lower than the time and MW-weighted average of the respective resource's default or resource-specific MOPR Floor Offer Price.

Because MOPR Floor Offer Prices will differ based on whether a Capacity Resource has previously cleared an RPM Auction, PJM is adding two new defined terms to clarify application of the rules and distinguish between new entry and cleared resources: "New Entry Capacity Resources" and "Cleared Capacity Resources with State Subsidies." New CTs, new CCs, and Capacity Resources with State Subsidies (including new uprates) that have not cleared in an RPM Auction pursuant to a Sell Offer at or above its resource-specific MOPR Floor Offer Price or the applicable default New Entry MOPR Floor Offer Price (other than any resources that qualify for a categorical

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[19] Offer prices must be greater than or equal to the default MOPR Floor Offer Price or actual costs as determined under a resource-specific review unless the Capacity Market Seller elects the competitive exemption for such Capacity Resource with State Subsidy.

[20] *See* proposed Tariff, Attachment DD, section 5.6.1(h).

exemption) will be collectively referred to as "New Entry Capacity Resources."[21] Sell Offers for New Entry Capacity Resources may be no lower than the MOPR Floor Offer Price based on the cost of new entry ("CONE") (less net expected energy and ancillary services ("E&AS") revenues) for the resource (i.e, Net CONE). As always, Capacity Market Sellers will be able to elect to use a default MOPR Floor Offer Price or may seek a resource-specific value through the resource-specific exception.[22]

Capacity Resources remain New Entry Capacity Resources until they clear an RPM Auction based on their Sell Offer at or above their resource-specific or default MOPR Floor Offer Price.[23] Once a New Entry Capacity Resource clears in such fashion, then different MOPR offer rules apply. Consistent with the existing MOPR implementation, if the cleared resource is a CT or a CC and it does not receive a State Subsidy, then it is no longer subject to the MOPR and may offer at any level it chooses up to the applicable Capacity Market Seller Offer Cap. On the other hand, if the cleared resource is a Capacity Resource with State Subsidy, then it becomes a "Cleared Capacity Resource with State Subsidy" and continues to be subject to the MOPR. But, its MOPR Floor Offer Price will be based on its going-forward costs, i.e., its Avoidable Cost Rate ("ACR") (less net expected E&AS revenues) (i.e., Net ACR), which may be a resource-specific or a default value based on its resource type.[24]

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21 To be clear, Capacity Resources that cleared an RPM Auction before it received or became eligible to receive a State Subsidy cannot be New Entry Capacity Resources. *See* proposed Tariff, Definitions C-D (definition of Cleared Capacity Resource with State Subsidy).

22 Proposed Tariff, Attachment DD, section 5.14(h)(2)(A).

23 Proposed Tariff, Definitions L-M-N (definition of New Entry Capacity Resource).

24 Proposed Tariff, Definitions C-D (definition of Cleared Capacity Resource with State Subsidy). While it is conceivable that a Capacity Market Seller of a new Capacity Resource may attempt to time a State Subsidy so that resource is not entitled to it at the time of the RPM Auction for the resource's first year (and therefore the resource could avoid being subject to MOPR based on its cost of new entry), such behavior would be easily detectable given the publicly available record

In addition, Capacity Resources that initially are not entitled to a State Subsidy at the time they first cleared an RPM Auction,[25] but later became entitled to a State Subsidy for a subsequent Delivery Year (i.e., not a Delivery Year in which the resource already has an RPM commitment) would also be deemed as Cleared Capacity Resources with State Subsidy that would be subject to the MOPR. In other words, any Capacity Resource that has cleared in an RPM Auction before the December 19 Order, and is now entitled to a State Subsidy, would be a Cleared Capacity Resource with State Subsidy. Likewise, going forward, any Capacity Resource that is not entitled to a State Subsidy and clears an RPM Auction, and subsequently becomes entitled to a State Subsidy would then become a Cleared Capacity Resource with State Subsidy.

Capacity Resources that clear an RPM Auction without any benefit from a State Subsidy, or even the promise of a future benefit (as it is not "entitled" to a subsidy) based on an offer that presumably would account for recovery of the resource's construction and development cost, should not continue to be subject to the MOPR at the new entry cost (CONE) because the market has demonstrated a need for such resource based on its economic merit. Accordingly, if such a resource later receives a subsidy, it is proper to view a competitive offer from such Capacity Resource to be based only on its going-forward costs (ACR).

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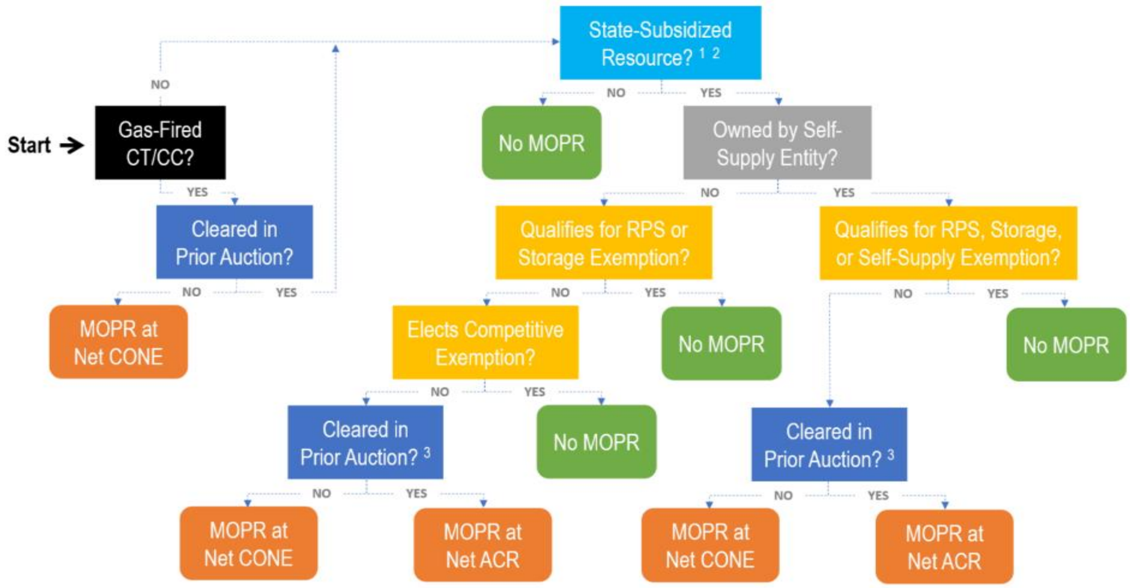
associated with State Subsidies. This would result in a referral to the Commission's Office of Enforcement for possible market manipulation.

25 Because such resources (including CT and CC resources) would not be Capacity Resources with State Subsidy, they would not be subject to the MOPR and could offer in at any price, without needing to elect a competitive exemption.

For clarity, the following graphic below provides a high-level overview of the application of the modified MOPR and what default MOPR Floor Offer Price applies in various circumstances.



1 A Capacity Resource committed to the FRR Alternative is not considered state-subsidized solely as a result of that commitment.

2 A Capacity Resource is still considered to be entitled to receive a State Subsidy following the sunset of the subsidy if the resource previously received a State Subsidy, and has not cleared an RPM Auction since that time.

3 New state-subsidized Capacity Resources must first clear an RPM Auction subject to the Net CONE offer price floor before being considered "Cleared in Prior Auction."

In the following sections, PJM describes the revised rules for determining how resources qualify as Capacity Resources with State Subsidy, and how such a resource may avoid the MOPR by qualifying for a categorical or competitive exemption (and avoid being subject to the MOPR), or may offer below the default MOPR Floor Offer Price through the resource-specific exception. Then, PJM details the default MOPR Floor Offer Price values and the process for Capacity Market Sellers to seek a resource-specific exception to such default values and set a floor price based on the resource's actual costs.

B. The Proposed Tariff Revisions Incorporate the Commission's Definition of State Subsidy for Determining Which Resources May Be Subject to the Modified MOPR. PJM Also Proposes to Provide High Level Guidance on Application of the Commission's Subsidy Definition.

1. Commission Directive

In the December 19 Order, the Commission found that application of PJM's MOPR should be expanded to resources receiving, or entitled to receive, "out-of-market payments provided or required by" a state, i.e., subsidized resources.[26] To aid in identifying resources subject to this modified MOPR, the Commission provided a definition of the term "State Subsidy."[27] However, the Commission clarified that its State Subsidy definition "is not intended to cover every form of state financial assistance that might indirectly affect FERC-jurisdictional rates or transactions."[28] Rather, it "focuses" on those payments that "squarely impact" electricity production or new or continued participation in the capacity market.[29] Accordingly, the Commission found it reasonable to exclude certain types of out-of-market payments from being considered State Subsidies, including "generic industrial development and local siting support" from being considered State Subsidies.[30] Further, the Commission excluded "private," "voluntary, arm's length bilateral transactions" from the types of out-of-market payment sources that would subject a resource to the modified MOPR.[31]

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26 December 19 Order at P 68.

27 December 19 Order at P 67.

28 December 19 Order at P 68.

29 December 19 Order at P 68.

30 December 19 Order at P 83. The Commission also excluded federal subsidies from the types of out-of-market payments that would subject a resource to the MOPR. December 19 Order at P 89.

31 December 19 Order at P 70.

2. *PJM Compliance Language*

a. Definition of State Subsidy

As directed by the December 19 Order, PJM is submitting the Commission's definition of "State Subsidy" in its Tariff, with non-substantive modifications.[32] Thus, State Subsidies shall include "direct or indirect payment, concession, rebate, subsidy, non-bypassable consumer charge, or other financial benefit that is [] a result of any action, mandated process, or sponsored process of a state government, a political subdivision or agency of a state, or an electric cooperative formed pursuant to state law"[33] and:

> (1) is derived from or connected to the procurement of (a) electricity or electric generation capacity sold at wholesale in interstate commerce, or (b) an attribute of the generation process for electricity or electric generation capacity sold at wholesale in interstate commerce; or
>
> (2) will support the construction, development, or operation of a new or existing capacity resource; or
>
> (3) could have the effect of allowing the unit to clear in any PJM capacity auction.[34]

To the extent a resource receives or is eligible to receive any revenue associated with the foregoing, it is a Capacity Resource with State Subsidy.

To provide further guidance and reduce any ambiguity on what is not a State Subsidy, PJM also proposes to include programs that categorically will not be considered

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32 December 19 Order at P 67. The non-substantive modifications to the definition of State Subsidy include a slight change in the structure and also lists explicit programs (discussed below) that, consistent with the December 19 Order, are not deemed as a State Subsidy. The explicit exclusions will help reduce any uncertainty that such programs are properly excluded from the definition of State Subsidy.

33 December 19 Order at P 67.

34 December 19 Order at P 67.

a State Subsidy. More particularly, PJM is proposing to codify in its Tariff that the following items are not State Subsidies:

> (a) payments, 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 designed to incent siting facilities in that county or locality rather than another county or locality;
>
> (b) state action that imposes a tax or assesses a charge utilizing the parameters of a regional program on a given set of resources notwithstanding the tax or cost having indirect benefits on resources not subject to the tax or cost (e.g., Regional Greenhouse Gas Initiative);
>
> (c) any indirect benefits to a Capacity Resource as a result of any transmission project approved as part of the Regional Transmission Expansion Plan;
>
> (d) any contract, legally enforceable obligation, or any rate pursuant to the Public Utility Regulatory Policies Act or any other state-administered federal regulatory program (e.g., the Cross-State Air Pollution Rule);
>
> (e) any state-directed default service procurement program that is competitively procured without regard to resource fuel type (e.g., New Jersey Basic Generation Service, Maryland Standard Offer Service);
>
> (f) any revenues for providing capacity as part of an FRR Capacity Plan or through bilateral transactions with FRR Entities; or
>
> (g) any voluntary and arm's length bilateral transaction (including but not limited to those reported pursuant to Tariff, Attachment DD, section 4.6), such as a power purchase agreement or other similar contract where the buyer is a Self-Supply Entity and the transaction is (1) a short term transaction (one-year or less) or (2) a long-term transaction that is the result of a competitive process that was not fuel-specific and is not used for the purpose of supporting uneconomic construction, development, or operation of the subject Capacity Resource, provided however that if the Self-Supply Entity is responsible for offering the Capacity Resource, the specified amount of installed capacity purchased by such Self-Supply Entity shall be considered to receive a State Subsidy in the

> same manner, under the same conditions, and to the same extent as any other Capacity Resource of a Self-Supply Entity.[35]

Item (a) above is taken from PJM's October 2018 filing[36] and is a vehicle for providing general development and siting support. The Commission, in the December 19 Order, accepted excluding these generic subsidies, which are unrelated to the supply-side participation, from consideration as State Subsidies.[37]

PJM is including item (b) to remove any potential ambiguity regarding the applicability of the revised MOPR with respect to payments related to the Regional Greenhouse Gas Initiative ("RGGI") and similar programs. Such regulatory schemes do not provide a "payment, concession, rebate, subsidy, non-bypassable consumer charge, or other financial benefit" directly or indirectly to a resource.[38] Because such programs do not "support[] the entry or continued operation of preferred generation resources that may not otherwise be able to succeed in a competitive wholesale capacity market,"[39] they are not State Subsidies that would trigger application of the MOPR. For example, as PJM has explained, the central feature of RGGI is a regional cap on CO_2 emissions, i.e., an emissions limitation, is just like any other environmental regulation or limit on power plant operations, whether for NO_x or SO_2 emissions or water discharge rates.[40] Such performance limitations cannot be considered subsidies to the affected resources or the unaffected resources that may indirectly benefit by not being subject to such state

35 Proposed Tariff, Definitions R-S (definition of State Subsidy).

36 *See* Initial Submission of PJM Interconnection, L.L.C., Docket Nos. EL16-49-000, et al., at 20-21 (Oct. 2, 2018).

37 December 19 Order at P 83.

38 December 19 Order at P 19.

39 December 19 Order at P 68.

40 Request for Rehearing and Request for Clarification of PJM Interconnection, L.L.C., Docket Nos. EL16-49-002, et al., at 22 (Jan. 21, 2020) ("PJM Rehearing Request").

imposed costs. PJM has limited the blanket exception to taxes and costs imposed by use of parameters of a regional program. Since the application of the subsidy definition to the RGGI program has been brought into question in this proceeding through Commissioner Glick's dissent, it is prudent to clarify in the Tariff that such programs are appropriately exempted from the definition of State Subsidy.[41] This exception does not exclude consideration of other programs which may be similarly structured but not be regional in nature. However, for purposes of crafting a blanket exemption (as opposed to case-by-case exemption), PJM has crafted the language to be responsive to specific concerns raised in the stakeholder process as to the application of the State Subsidy definition with respect to the RGGI program. [42]

Inclusion of item (c) clarifies, consistent with the December 19 Order, that any Capacity Resource that may indirectly benefit from transmission investments that are a result of the Regional Transmission Expansion Plan are excluded from classification as State Subsidies. Specifically, this exclusion pertains to resources that may stand to benefit because of the ability to use new transmission assets associated with state public policies that are built and funded pursuant to the State Agreement Approach embodied in PJM's transmission planning process.[43] In other words and by way of example, if a state subsidizes transmission assets through the State Agreement Approach outlined in the PJM Tariff, any Capacity Resources that subsequently use such transmission assets should not be deemed to have received a state subsidy. This is appropriate given that

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41 December 19 Order, dissenting op. (Commissioner Glick) at P 17.

42 A number of PJM states are either today participants in the RGGI program or indicated their intent to participate going forward making this clarification and proposed clarification particularly relevant and needed at this time.

43 *See* Operating Agreement, Schedule 6, section 1.5.9.

such transmission projects are recoverable under PJM's Tariff and approved by the Commission.

Inclusion of item (d) clarifies, consistent with the December 19 Order,[44] that any federal program that may be administered by a state are not State Subsidies. In particular, the Public Utility Regulatory Policies Act of 1978[45] derived benefits are not considered State Subsidies, as they are part of a federal program.[46] This could also include state-administered Federal air pollution regulations such as the Cross-State Air Pollution Rule. Any payments received by Capacity Resources as a result of selling excess emission allowances to another resource owner should not be deemed a State Subsidy given that the genesis of such emission trading are based on state programs that are derived from specific authority granted by the Congress through the Clean Air Act[47] or other such federal legislation.

Inclusion of item (e) clarifies that a state-directed default service procurement program also would not operate as a regime that qualifies as a State Subsidy subjecting resources to the MOPR. These state programs are mechanisms by which load-serving entities in retail choice states acquire obligations to provide energy and related services to retail customers through a state-directed competitive and non-discriminatory auctions. The resources which are chosen in those auctions are being paid for their providing service to load serving entities and have been chosen through a competitive state auction and resource neutral. For this reason, PJM does not see any basis for finding these

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[44] December 19 Order at P 89.

[45] Public Utility Regulatory Policies Act, Pub. L. No. 95–617, 92 Stat. 3117 (1978).

[46] *See* December 19 Order at P 67 n.143.

[47] 42 U.S.C. § 7401.

auctions to represent state subsidies within the definition of subsidy in the Order. To eliminate any uncertainty on this point, PJM proposes to explicitly exempt such state-directed default service procurement programs from the definition of State Subsidy for MOPR purposes.

Item (f) ensures that participation in an FRR Capacity Plan does not provide a basis for a Capacity Resource becoming subject to the MOPR. Such participation in a Commission-approved means for providing capacity in the PJM Region does not amount to a State Subsidy. This is clear from the December 19 Order where the Commission affirmed the existing FRR Alternative in the context of the modified MOPR provisions.[48] As such, any payment received through such participation should not constitute a State Subsidy.

Finally, PJM is including item (g) to ensure continuing viability and liquidity in the secondary markets for bilateral transactions from non-subsidized resources. There, PJM is excluding from the definition of State Subsidy revenues associated with "any voluntary, arm's length bilateral transaction"[49] in which an owner of a non-subsidized resource may bilaterally transact a part or all of the capacity, energy, or ancillary services from its facility to a Self-Supply Entity[50] without jeopardizing the non-subsidized status

48 December 19 Order at P 204.

49 December 19 Order at P 70.

50 PJM is proposing to define a "Self-Supply Entity" as the following types of Load Serving Entity that operate under long-standing business models: single customer entity, public power entity, or vertically integrated utility, where "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; "single customer entity" means a Load Serving Entity that serves at retail only customers that are under common control with such Load Serving Entity, where such control means holding 51% or more of the voting securities or voting interests of the Load Serving Entity and all its retail customers; and "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." Proposed Tariff, Definitions R-S (definition of Self-Supply Entity).

of the underlying generating facility (while the capacity transacted to the Self-Supply Entity would be considered a Capacity Resource with State Subsidy). Not every transaction would insulate the Capacity Market Seller. Rather, to ensure no improper transference of subsidy, the transaction would need to be either short-term, of one year or less, or "a long-term transaction that is the result of a competitive process that was not fuel-specific and is not used for the purpose of supporting uneconomic construction, development, or operation of the subject Capacity Resource."[51] These bounds are reasonable, as they ensure the underlying resource does not gain a benefit from the State Subsidy. Specifically, short-term transactions that are less than one year are generally used to ensure sufficient capacity by a Self-Supply Entity in the event a resource owned or contracted by the Self-Supply Entity becomes unavailable. Long term transactions with a Self-Supply Entity that are a result of a competitive process, not fuel-specific, and not used to support the uneconomic construction, development, or operation of the resource should also not be deemed a State Subsidy. This is consistent with the Commission's December 19 Order that "voluntary, arm's length bilateral transactions" do not raise inappropriate subsidy concerns,[52] particularly when such transaction is not used to support the construction, development, or operation of the resource. This exclusion ensures Self-Supply Entities retain access to the secondary market—because Capacity Market Sellers will not be afraid of transacting with them (such as through in a unit-specific capacity transaction) for fear of tainting their resource as State Subsidized.[53]

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51 Proposed Tariff, Definitions R-S (definition of State Subsidy).

52 December 19 Order at P 70.

53 Although the above MOPR rules are intended to apply to Incremental Auctions ("IA") as well as the Base Residual Auction, PJM is proposing no special rules in the narrow circumstance associated with replacement transactions undertaken when the Capacity Market Seller can demonstrate the inability of its Capacity Resource to meet its capacity commitment during a

b. Capacity Resource with State Subsidy

The December 19 Order directed PJM to expand the scope of the MOPR to also apply to Capacity Resources that receive or are entitled to receive State Subsidy. To facilitate application of the modified MOPR to such resources, PJM has defined the term "Capacity Resource with State Subsidy," which, generally speaking, is any Capacity Resource that receives or is entitled to receive a State Subsidy.

However, because the effects of State Subsidies may also be indirect and there are many paths by which a State Subsidy may impact the level of costs a Capacity Market Seller needs to recover in the capacity market, PJM has identified three other scenarios in which a Capacity Resource will be considered subject to the MOPR as a Capacity Resource with State Subsidy. One, as directed by the December 19 Order,[54] a Capacity Resource that was once subsidized but is no longer receiving or entitled to receive a State Subsidy and has not cleared an RPM Auction since it last received the benefit of such

limited period between the Third IA on one hand and six months prior to the delivery year on the other. Generally, replacement transactions can only be entered into after the Equivalent Demand Forced Outage Rate ("EFORd") for the Delivery Year has been locked in the Capacity Exchange system (November 30 prior to the Delivery Year). After November 30 prior to the Delivery Year and prior to the conduct of the Third IA for the Delivery Year, the commitment of such a resource may be replaced but only up to the quantity of any commitment deficiency of the resource caused by the differences between sell offer EFORd and Final EFORd, and/or derating (as opposed to replacing the entire resource). In limited instances, a Capacity Market Seller may replace any or all of a resource's capacity commitment prior to the Third IA, but only to the extent that the Capacity Market Seller of the replaced resource provides transparent and verifiable evidence of the inability for such resource to meet its capacity commitment to PJM and the Market Monitor. Acceptable reasons for such replacement include deactivation of the resource, cancellation of a planned resource, or delay in in-service date. PJM Manual 18: *PJM Capacity Market*, Revision: 44 at section 8.8 (Replacement Resources) (Dec. 9, 2019). Due to this limited utility, it is acceptable to allow subsidized resources to be used as replacement capacity because they have very limited opportunity to displace unsubsidized resources in the RPM Auctions. Further, if it is determined that a Market Participant deliberately circumvents the MOPR rules by replacing an unsubsidized committed Capacity Resource with a Capacity Resource with State Subsidy, PJM and the Market Monitor can refer such Market Participant to the Commission's Office of Enforcement.

54 December 19 Order at P 75 ("We further find that a capacity resource should be considered to be entitled to receive a State Subsidy if the resource previously received a State Subsidy, and has not cleared a capacity auction since that time.").

State Subsidy shall be considered to be a Capacity Resource with State Subsidy and subject to the MOPR as either a New Entry Capacity Resource or a Cleared Capacity Resource with State Subsidy, depending on whether and how it has previously cleared an RPM Auction.

Two, Capacity Resources for which the Capacity Market Seller does not own the underlying generating facility but may nonetheless benefit from any State Subsidy received by the resource's owner will also be considered a Capacity Resource with State Subsidy. For example, the owner of an Intermittent Resource may retain or sell renewable energy credits ("RECs") to one entity while selling the capacity rights to another entity. In this scenario, although the Capacity Market Seller of such Capacity Resource may technically not be entitled to a State Subsidy (because the contract provides only the capacity rights for the resource to the Capacity Market Seller and not the RECs), the resource should still be subject to the MOPR because the owner of such Intermittent Resource may be able to transact the capacity rights to the Capacity Market Seller for less than its actual costs due to other revenues derived from the renewable energy credits. Accordingly, PJM is proposing to consider as a Capacity Resource with State Subsidy any

> Capacity Resource that is the subject of a bilateral transaction (including but not limited to those reported pursuant to Tariff, Attachment DD, section 4.6) shall be deemed a Capacity Resource with State Subsidy to the extent the transacting owner of the facility supporting the Capacity Resource is entitled to a State Subsidy associated with such facility even if the Capacity Market Seller is not entitled to a State Subsidy.[55]

[55] Proposed Tariff, Definitions C-D (definition of Capacity Resource with State Subsidy).

By applying the MOPR to this class of Capacity Resources, PJM is ensuring that all Capacity Resources receiving the benefit of a State Subsidy are subject to the MOPR and will be required to offer in at or above a level near their actual unsubsidized net cost to provide capacity.

Three, the final group of Capacity Resources that should also be considered Capacity Resources with State Subsidy are those that are supported by a jointly owned facility and one of the other owners of the facility is entitled to receive or receives a State Subsidy. The broad expansion of the MOPR to new and existing resources of all types necessarily is complex and intrudes all facets of resource ownership and participation in the capacity market. Given the capital intensive nature of generation resource development, many resources are jointly owned, and the joint owners are from all sectors of the industry: public power, merchant, and vertically-integrated. There are many important benefits of joint ownership in developing and maintaining the resource fleet across the PJM Region and PJM has long appropriately accommodated such a business model. Indeed, PJM's capacity market rules recognize this reality, and that created by the robust bilateral market, by defining Capacity Resources as only megawatts ("MWs") and not the physical resource.[56] This allows each owner to independently participate in PJM's capacity and other markets, at the offer price it determines. In other words, a single facility can (and often does) support multiple Capacity Resources.

However, because these Capacity Resources are not truly independent of each other, as they are each supported by the same facility, the public benefits received by one owner can affect the ownership costs of the others, effectively providing a cross-subsidy

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[56] *See* RAA, Article 1 ("'Capacity Resources' shall mean megawatts of . . . .").

among the owners. The easily severable nature of the output and attributes of a single facility therefore raises concerns in this context where the Commission is trying to dampen the effects of any State Subsidy in the capacity market. Therefore, PJM is proposing a general rule to apply the MOPR to Capacity Resources supported by a jointly owned facility in which at least one owner receives or is entitled to receive a State Subsidy.

But not all joint ownership arrangements allow for cross-subsidization among owners. Accordingly, PJM's proposed MOPR implementation provisions do not apply the MOPR to Capacity Resources where the benefit of a State Subsidy received by one owner are effectively severable and assignable to specific owners among the class of joint owners. Thus, any Capacity Resource supported by a facility where the joint ownership arrangement provides that "the material rights and obligations of such generating facility are in *pari passu*, meaning that such rights and obligations are allocated among the owners pro rata based on ownership share" will *not* be considered a Capacity Resource with State Subsidy (to the extent that owner is not otherwise entitled to a State Subsidy).[57] Excluding such Capacity Resources from the MOPR is reasonable. Joint ownership arrangements that are in *pari passu* are designed to ensure all owners have equal rights and responsibilities proportionate to their ownership share. Thus, each owner is responsible only for its costs and, absent additional agreement, cannot not cross-subsidize other owners. Such owners should also have the right to all benefits associated with their proportionate share of energy output, such that, for example, an owner of 40% of a 100 MW wind farm would be entitled to all the RECs associated with those 40 MW,

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[57] Proposed Tariff, Definitions I-J-K (definition of Jointly Owned Cross-Subsidized Capacity Resource).

be able to offer into RPM all the capacity associated with those 40 MW, and, importantly, be responsible for 40% of the costs of the entire facility. With these provisions, PJM is able to balance the December 19 Order's directive to extend the MOPR to resources receiving the benefit of State Subsidies against accommodating (and not hampering with) a long-standing business model that has ensured the PJM Region has a large and diverse resource fleet.

On the other hand, where the share of rights and obligations are disproportional with the ownership share of a joint resource, State Subsidy benefits to one owner may pass through to other joint owners. Accordingly, jointly owned resources that are not in *pari passu*, where at least one joint owner is entitled to a State Subsidy, is subject to the MOPR. For clarity and ease of implementation, PJM has defined these jointly owned Capacity Resources which are subject to the MOPR as "Jointly Owned Cross-Subsidized Capacity Resources."[58]

The presumption of whether or not a Capacity Resource is a Jointly Owned Cross-Subsidized Capacity Resource may be overcome by either the Capacity Market Seller demonstrating that there is no cross-subsidization to the Office of the Interconnection, with review and input from the Market Monitor, or the Office of the Interconnection, with review and input from the Market Monitor, finds based on sufficient evidence, that there is cross-subsidization.[59]

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58 Proposed Tariff, Definitions I-J-K (definition of Jointly Owned Cross-Subsidized Capacity Resource) ("[A] Capacity Resource that is supported by a resource that is jointly owned, where at least one owner is entitled to or receives a State Subsidy associated with such Capacity Resource, shall be a Capacity Resource with State Subsidy . . . .").

59 Proposed Tariff, Definitions I-J-K (definition of Jointly Owned Cross-Subsidized Capacity Resources).

c. Process for Capacity Market Sellers to certify to PJM whether their resources qualify as Capacity Resources with State Subsidy

Taking advantage of the fact that Capacity Market Sellers know best whether their Capacity Resources are receiving or are entitled to receive a State Subsidy, PJM is proposing that Capacity Market Sellers inform PJM of the status of their resources.[60] PJM envisions that this certification process would be accomplished electronically, as a "check the box" line item, and the Capacity Market Seller will affirmatively certify, for each resource, whether the resource is—or is not—a Capacity Resource with State Subsidy, and if so, "identify (with specificity) any State Subsidy,"[61] i.e., the specific state or local program that is the subject of the State Subsidy.

To ensure orderly administration of pre-RPM Auction processes and deadlines (e.g., resource-specific exception requests), Capacity Market Sellers must provide this certification for each Capacity Resource (other than Demand Resource and Energy Efficiency) they intend to offer into the RPM Auction no later than 120 days prior to the relevant RPM Auction. Capacity Market Sellers that intend to offer Demand Resources or Energy Efficiency Resources into an RPM Auction will be required to certify whether or not such resources qualify as a Capacity Resource with a State Subsidy no later than 30 days prior to the commencement of the offer period of any RPM Auction.[62] The reason for this timing distinction is simple—the registration process for end-use customer locations associated with the Demand Resource Sell Offer Plan is much closer to the

60 *See* proposed Tariff, Attachment DD, section 5.14(h)(1)(C)(i).

61 Proposed Tariff, Attachment DD, section 5.14(h)(1)(C)(i).

62 Proposed RAA, Schedule 6, sections A(5) & A-1(3); proposed Tariff, Attachment DD-1, sections A(5) & A-1(3).

conduct of the RPM Auction given potential end-use customer switching.[63] In addition, the measurement and verification plan for Energy Efficiency Resources is submitted to PJM no later than 30 days prior to the relevant RPM Auction. Certification of whether a Demand Resource or Energy Efficiency Resource qualifies as a Capacity Resource with State Subsidy no later than 30 days prior to the auction provides Capacity Market Sellers of Demand Resources and Energy Efficiency Resources with a reasonable amount of time to ensure that the Demand Resource Sell Offer Plan and measurement and verification plan contain up-to-date participant information prior to the relevant RPM Auction and submitted concurrently with the other respective requirements for these resources.[64]

All Capacity Market Sellers will have a continuing obligation to notify PJM and the Market Monitor of any material changes regarding whether or not a Capacity Resource is eligible for a State Subsidy. In addition, the Capacity Market Seller will be required to notify PJM and the Market Monitor of any material changes to the applicable state or local program that is the subject of the State Subsidy.[65] More particularly, Capacity Market Sellers of a Capacity Resource that becomes eligible or becomes no longer eligible for a State Subsidy must notify PJM within five days of any such change.

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[63] Consistent with this rule, PJM will also propose requiring the Demand Resource Sell Offer Plan to be submitted no later than 30 days prior to the RPM Auction from the current 15 days prior to the RPM Auction in RAA, Schedule 6. Proposed RAA, Schedule 6, sections A(5) & A-1(3); proposed Tariff, Attachment DD-1, sections A(5) & A-1(3).

[64] Notwithstanding, a Capacity Market Seller that does not submit a resource-specific exception for a Capacity Resource with State Subsidy by 120 days prior to the relevant RPM Auction will not have the option to obtain a resource-specific default MOPR Floor Offer Price. Thus, if a Capacity Market Seller does not certify whether or not a Demand Resource or Energy Efficiency Resource qualifies as a Capacity Resource with State Subsidy 120 days prior to the relevant RPM Auction, such Capacity Market Seller will be precluded from seeking a resource-specific exception for such resources(s) for that auction.

[65] Proposed Tariff, Attachment DD, section 5.14(h)(1)(C)(iii).

A resource's status as a Capacity Resource with State Subsidy (or not) will remain unchanged, even if the Capacity Market Seller of the resource changes, unless one of three things occurs: the Capacity Market Seller of the resource notifies PJM of a change; PJM affirmatively changes the resource's status; or the Commission issues an order directing a change to the resource's status.[66] PJM will only change a resource's status if it determines that fraud or material misrepresentation occurred with regard to the resource's current status, or the Commission orders a change in status, as discussed below.[67] This approach means that the Capacity Market Seller will not be required to re-certify whether or not the Capacity Resource is eligible for a State Subsidy prior to each RPM Auction, unless the State Subsidies applicable to the resource changes.

Capacity Market Sellers that fail to certify whether its resource(s) is eligible for a State Subsidy by the applicable deadline shall be subject to the default MOPR Floor Offer Price with no ability to elect the resource-specific exception,[68] unless the Capacity Market Seller receives a waiver from the Commission or it previously received a resource-specific exception.[69] This is a reasonable outcome because timely notification

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66 Proposed Tariff, Attachment DD, section 5.14(h)(1)(C)(iii).

67 *See* proposed Tariff, Attachment DD, section 5.14(h)(9) (Procedures and Remedies in Cases of Suspected Fraud or Material Misrepresentation or Omissions in Connection with a Capacity Resource with State Subsidy).

68 Capacity Market Sellers of Demand Resources and Energy Efficiency Resources that fail to notify PJM whether such resources are subject to a State Subsidy by the deadline of 30 days prior to the BRA would also not have the ability to elect the resource-specific exception given that the deadline to elect the resource-specific exception of 120 days prior to the BRA would have already passed. However, the proposed provisions would allow a Capacity Market Seller to use a resource-specific MOPR Floor Offer Price submitted in advance of the 120 day deadline (to the extent it was subsequently approved), regardless of whether the Capacity Market Seller timely certified whether or not the resource is eligible for a State Subsidy.

69 Proposed Tariff, Attachment DD, section 5.14(h)(1)(C)(i). The certification requirements do not apply to resources that are exempt from the MOPR, or to resources "for which the Market Seller designated whether or not it is subject to a State Subsidy in a prior Delivery Year." Proposed Tariff, Attachment DD, section 5.14(h)(1)(C)(ii).

of whether a resource is entitled to a State Subsidy is necessary to allow for an orderly conduct of the RPM Auction.[70] At the same time, such a rule does not prevent such resources from being offered in the RPM Auctions altogether, which would otherwise create a loophole that allow Capacity Market Sellers to circumvent the must-offer requirements.[71]

d. Non-binding guidance for Capacity Market Sellers as to whether their resources qualify as Capacity Resources with State Subsidy

To provide further clarity and reduce uncertainty, PJM and the Market Monitor will work together to develop a non-exhaustive list of programs, based on information provided by Capacity Market Sellers, that they consider to be a State Subsidy and post this list in a guidance document. Given the myriad state and local programs that may exist throughout the PJM Region and the fact that such programs may change over time, it would not be practical to include a list of specific State Subsidies in the Tariff. Instead, PJM will develop and maintain, in collaboration with the Market Monitor, a list of specific State Subsidies to provide guidance on many of the most common programs that may be applicable to Capacity Resources. Importantly, however, it is ultimately the Capacity Market Seller's responsibility to ensure that they correctly certify whether its

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70 As further described below, PJM proposes to require Capacity Market Sellers to submit all resource-specific exception requests to PJM and the Market Monitor no later than 120 prior to the conduct of the relevant RPM Auction. This timeline is necessary to allow PJM and the Market Monitor to review the resource-specific exception and resolve any disagreements with the Capacity Market Seller prior to the conduct of the auction.

71 Notwithstanding, in the event a Capacity Market Seller does not timely specify whether or not a Capacity Resource is eligible for a State Subsidy and such Capacity Resource does not have a default MOPR Floor Offer Price and has not submitted and received approval of a resource-specific exception, PJM will consider such Sell Offer as incomplete and reject the offer, preventing the resource from clearing the relevant RPM Auction.

Capacity Resource is subject to a State Subsidy, irrespective of any guidance provided by PJM and the Market Monitor.[72]

The burden of identifying whether a resource is receiving (or entitled to receive) a State Subsidy appropriately falls on the Capacity Market Seller.[73] The Capacity Market Seller is best positioned to know the specific benefits and eligibility requirements of any available subsidy. The Capacity Market Seller is in the business of developing, constructing, operating, and maintaining the resource, and is in contact with each state and local regulatory body with authority over the resource. Further, the Capacity Market Seller is in control over the resource's finances and is aware of each benefit available to it.

By contrast, PJM cannot possibly know each direct and indirect benefit a resource is receiving (or is entitled to receive) from state or local governments. Nor can PJM be aware of each direct and indirect benefit the 13 states and innumerable local governments may make available to resources in the PJM Region. PJM cannot track these benefits and determine each resource that is entitled to them. Accordingly, Capacity Market Sellers will notify PJM whether a resource is receiving, or is entitled to receive, a State Subsidy. If the Capacity Market Seller so indicates, then such resource is a Capacity Resource with

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72 *See* Proposed Tariff, Attachment DD, section 5.14(h)(1)(C)(i) ("All Capacity Market Sellers shall be responsible for each certification irrespective of any guidance developed by the Office of the Interconnection and the Market Monitoring Unit.").

73 *See Cal. Indep. Sys. Operator Corp*., 106 FERC ¶ 61,179, at P 33 (2004) ("The integrity of the [California System Operator Corporation] market, in part, depends upon market participants adhering to market rules. We require market participants to follow the rules regardless of whether a failure to do so can be associated directly with adverse affects on market prices. The integrity of the marketplace and the reliability of service rendered are tied to confidence that the rules are being followed.").

State Subsidy and it will be subject to the MOPR unless it meets a categorical exemption or elects the competitive exemption.[74]

PJM proposes that such certifications be subject to the fraud and misrepresentation rules discussed below. As such, in lieu of requiring Capacity Market Sellers to provide supporting information along with the notification, PJM and the Market Monitor shall have the authority to request information supporting a Capacity Market Seller's certification.[75] This will provide PJM, with input and advice of the Market Monitor, with the ability to verify the accuracy of a Capacity Market Seller's representation.

C. PJM Will Exempt Certain Resources Owned or Contracted By Self-Supply Entities from Being Subject to the MOPR.

1. Commission Directive

In the December 19 Order, the Commission directed PJM to include a self-supply exemption from the MOPR for certain resources that are owned by Self-Supply Entities. In particular, the Commission stated that resources are owned by Self-Supply Entities and (a) have successfully cleared an annual or incremental capacity auction prior to December 19, 2019; (b) have an executed interconnection construction service agreement on or before December 19, 2019; or (c) have an unexecuted interconnection construction service agreement filed by PJM for the resource with the Commission on or before December 19, 2019, would be exempt from the MOPR.[76]

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74 As discussed below, the resource-specific exception does not exempt resources from the MOPR. Rather, the floor offer price applicable in this instance is based on the resource's specific circumstances and is not the default MOPR Floor Offer Price for the resource type.

75 *See* Proposed Tariff, Attachment DD, section 5.14(h)(9).

76 December 19 Order at P 202.

2. *PJM Compliance Language*

Consistent with the December 19 Order, PJM will categorically exempt resources from the MOPR that are owned or bilaterally contracted by Self-Supply Entities if one of the following three criteria are met: (a) has successfully cleared an RPM Auction prior to December 19, 2019; (b) is the subject of "an interconnection construction service agreement, interim interconnection service agreement, interconnection service agreement or equivalent agreement" executed on or before December 19, 2019; or (c) is the subject of an unexecuted interconnection service agreement or equivalent agreement filed by PJM with the Commission on or before December 19, 2019, will be exempt from the MOPR.[77]

PJM clarifies that this exemption should apply so long as a resource is subject to an interconnection service agreement or equivalent agreement[78] executed or filed with the Commission on or before December 19, 2019. The distinction here is that not all resources may need an interconnection *construction* service agreement, which is only required to the extent network upgrades are required to accommodate the interconnection.[79] To properly capture the universe of all planned resources that "reasonably relied" on prior Commission orders, all resources that advanced to that final stage of the interconnection process and proceeded to interconnection service agreement, including interim interconnection service agreements, should be eligible for the

77 Proposed Tariff, Attachment DD, section 5.14(h)(5).

78 Wholesale market participation agreements ("WMPA") should also be included in this exemption, as it is another type of agreement that allows a generator that is interconnected to non-jurisdictional facilities to participate in PJM's markets, including the capacity market. Resources with a WMPA executed prior to December 19, 2019, are reasonably expected to participate in the capacity market and are also not be subject to the MOPR, consistent with the December 19 Order.

79 *See* PJM Rehearing Request at 21-22.

exemption.[80] In any of these cases, the Self-Supply Entity incurred investment costs to interconnect prior to the December 19 Order. This approach is consistent with the Commission's rationale for exempting such resources "because traditionally they have been exempt from application of the MOPR and market participants that reasonably relied on that guidance in formulating their business plans prior to the June [29] Order were not on notice that they would be mitigated."[81]

Further, while the December 19 Order explicitly included only resources that are owned by Self-Supply Entities as one of the requirements to qualify for this exemption, it is appropriate to also include resources that are bilaterally contracted by such Self-Supply Entities. The justification for limiting disruption to the self-supply industry and preserving existing investments applies equally to both resources that are owned or bilaterally contracted by a Self-Supply Entity. Thus, resources should be exempt from the MOPR regardless of whether it is owned or bilaterally contracted by a Self-Supply Entity because the decision to invest in such resources was made prior to the December 19 Order.

PJM also defines "Self-Supply Entity" to mean either a vertically integrated utility, a public power entity, or a single customer entity.[82] These three types of entities captures the universe of entities that employ the "self-supply" business model in PJM. A vertically integrated utility includes any utility that owns or bilaterally contracts

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80 Additionally, other Capacity Resources that have participated in the RPM Auctions may not have an interconnection service agreement with PJM for legacy resources that interconnected prior to the relevant transmission owner integrating into PJM.

81 December 19 Order at P 208 (footnote omitted) (discussing Capacity Storage Exemption); *see also id.* at P 174 (same for Renewable Portfolio Standards ("RPS") Exemption), P 203 (same for Self-Supply Exemption).

82 Proposed Tariff, Definitions (R-S) (definition of Self-Supply Entity).

generation and includes such generation in its regulated rates while earning a regulated return on its investment or cost recovery through bilateral contracts for such generation. The public power entities include 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. A single customer entity refers to a load serving entity that is majority owned by a municipality or cooperative and serves only retail customers. Resources owned or bilaterally contracted by either of such load serving entities may qualify for the self-supply exemption if any of the three criteria described above are met.

Given that PJM already has all the information pertaining to this categorical self-supply exemption, it is unnecessary for Self-Supply Entities that own or bilaterally contract such exempt resources to affirmatively elect this exemption. Instead, PJM intends to provide the relevant Self-Supply Entities with a list of their resources that qualify for this exemption. The Capacity Market Seller would then simply need to confirm whether they agree with the list of exempt resources.

D. PJM Will Exempt Certain Intermittent Resources from Being Subject to the MOPR.

1. Commission Directive

In the December 19 Order, the Commission directed PJM to include a limited exemption from the MOPR for certain renewable resources that are eligible to receive support from state-mandated or state-sponsored RPS. In particular, the Commission stated that Intermittent Resources that qualify for a state-mandated or state-sponsored RPS and (a) have successfully cleared an annual or incremental capacity auction prior to December 19, 2019; (b) have an executed interconnection construction service agreement on or before December 19, 2019; or (c) have an unexecuted interconnection construction service agreement filed by PJM for the resource with the Commission on or before December 19, 2019, would be exempt from the MOPR.[83]

2. PJM Compliance Language

Consistent with the December 19 Order, PJM will categorically exempt certain Intermittent Resources that qualify for a state mandated or state-sponsored RPS program from the MOPR if one of the following three criteria are met: an Intermittent Resource that (a) has successfully cleared an RPM Auction prior to December 19, 2019; (b) is the subject of an interconnection service agreement or equivalent agreement[84] executed on or before December 19, 2019; or (c) is the subject of an unexecuted interconnection service agreement or equivalent agreement filed by PJM with the Commission on or before December 19, 2019, will be exempt from the MOPR.[85] Under this exemption, any Intermittent Resources that generate RECs or equivalent credits that may otherwise receive or be eligible to receive a State Subsidy would not be subject to the modified MOPR if it existed prior to the December 19, 2019 date.

Similar to the self-supply exemption, it is appropriate to allow any Intermittent Resource that is the subject of any interconnection service agreement, rather than solely an interconnection *construction* service agreement, to qualify for the Intermittent Resource exemption. This is because interconnection service agreements, along with

83 December 19 Order at P 173.

84 WMPAs should also be included in this exemption, as it is another type of agreement that allows a generator that is interconnected to non-jurisdictional facilities to participate in PJM's markets, including the capacity market. Resources with a WMPA executed prior to December 19, 2019, reasonably expected to participate in the capacity market and are also not be subject to the MOPR, consistent with the December 19 Order.

85 Proposed Tariff, Attachment DD, section 5.14(h)(6).

interim interconnection service agreements, appropriately exempt any Intermittent Resources where investment decisions were made prior to the December 19 Order. This is consistent with the Commission's rationale that such prior investment decisions were based on the Commission's previous affirmative determinations that renewable resources had too little impact on the market to require review and mitigation.[86]

Given that PJM already has all information pertaining to this categorical exemption, it is unnecessary for Capacity Market Sellers of such resources to affirmatively elect this exemption. Instead, PJM intends to provide the relevant Capacity Market Sellers with a list of their resources that qualify for this exemption. The Capacity Market Sellers would then simply need to confirm whether they agree with the list of exempt Intermittent Resources.

E. Consistent with the Order, PJM Will Exempt Certain Demand Resources and Energy Efficiency Resources from Being Subject to the MOPR.

1. Commission Directive

In the December 19 Order, the Commission directed PJM to include a limited exemption from the MOPR for certain Demand Resources and Energy Efficiency Resources that receive or are eligible to receive a State Subsidy. In particular, the Commission directed PJM to include a MOPR exemption for Demand Resources and Energy Efficiency Resources that fulfill at least one of the following criteria: "(1) have successfully cleared an annual or incremental capacity auction prior to [December 19, 2019]; (2) have completed registration on or before the date of this order; or (3) have a

[86] December 19 Order at P 174.

measurement and verification plan approved by PJM for the resource on or before [December 19, 2019]."[87]

2. PJM Compliance Language

In accordance with the December 19 Order, PJM will categorically exempt certain Demand Resources and Energy Efficiency Resources that receive or may be entitled to receive a State Subsidy if such resources fulfill at least one of the following criteria: (a) has successfully cleared an RPM Auction prior to December 19, 2019. For purposes of this subsection (a), individual customer location registrations (or for utility-based residential load curtailment program, based on the total number of participating customers) that participated as Demand Resource and cleared in an RPM Auction prior to December 19, 2019, and submitted to PJM no later than 45 days prior to the BRA for the 2022/2023 Delivery Year may be deemed eligible for the Demand Resource and Energy Efficiency Resource Exemption; or (b) have completed registration on or before the date of this order; or (c) is supported by a post-installation measurement and verification report for Energy Efficiency Resources approved by PJM on or before December 19, 2019.[88]

a. Applying the exemption to Demand Resources

While it is generally clear which generation resource is "existing" and may be a Cleared Capacity Resource with State Subsidy, the same cannot be said for Demand Resources. The difficulty lies in the basic attribute of such Demand Resources—end-use customers willing to stop using energy when prices reach a certain level. Demand

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87 December 19 Order at P 208.

88 *See* proposed Tariff, Attachment DD, section 5.14(h)(7).

Resources are composed of registrations, which are in turn composed of many such end-use customers to reach an aggregate amount that can be offered into an RPM Auction.

Per current rules, Curtailment Service Providers must register such end-use customers with PJM only shortly before the applicable Delivery Year.[89] In order to account for this in the forward nature of the capacity market, the current rules provide that to be an "Existing Demand Resource" in a given RPM Auction the Demand Resource must consist solely of "identified existing end-use customer sites that are registered for the current Delivery Year with PJM (even if not registered by such Demand Resource Provider) and that the Demand Resource Provider reasonably expects to have under a contract to reduce load based on PJM dispatch instructions by the start of the Delivery Year for which such resource is offered."[90] That is, the aggregated MW cleared in an RPM Auction on Sell Offers for Demand Resources are comprised of MW provided by individual end-use customer locations, which may change from the original Curtailment Service Provider to another Curtailment Service Provider due to highly competitive nature of the load curtailment market, which results in customer switching between the time of the RPM Auction and the start of the Delivery Year.

Thus, whether a Sell Offer for a Demand Resource should be subject to the modified MOPR or be exempt should track the underlying participating end-use customer locations, rather than be a "look back" based only on aggregate MWs previously cleared on that Demand Resource. This will allow for end-use customer location switching from

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89 *See* RAA, Schedule 6, section A(5); proposed Tariff, Attachment DD-1, section A(5).

90 RAA, Article 1 – Definitions (Existing Demand Resource).

one Curtailment Service Provider to another[91] without negatively impacting the end-use customer's eligibility for the exemption from the modified MOPR. This will also avoid the creation of an "un-level playing field" by allocating a MW exemption to the Curtailment Service Provider based on the underlying customer location that may freely switch between Curtailment Service Providers in the future. As a result, for purposes of the Demand Resource exemption, PJM proposes to apply the exemption to participating end-use customers that were included in a Demand Resource registration used to support offers that cleared prior to December 19, 2019, as opposed to applying the exemption to the aggregated level of MWs cleared on the Demand Resource.[92]

Further, the exemption for a specific end-use customer or location should not be simply tied to the MW amount cleared for that location in a prior auction. Nomination values, or the amount of capacity that may be offered for each end-use customer, may vary based on factors outside the control of the customers, such as changes to the peak load contribution. The qualified load reduction amount for each end-use customer may significantly vary from year to year as the underlying Peak Load Contribution changes. The Peak Load Contribution is typically determined based on the end-use customer's load during the five coincident peak days where the customer's usage may significantly vary during such hours. The amount of capacity available from an end-use customer location may therefore be greater or less than the MW quantity that was previously nominated for such end-use customers in prior Demand Resource registrations for reasons outside their control. Thus, it is reasonable to exempt any end-use customer that

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91 End-use customer switching from one Curtailment Service Provider to another Curtailment Service Provider is commonplace.

92 *See* proposed Tariff, Attachment DD, section 5.14(h)(7)(A).

was included in a Demand Resource registration prior to December 19, 2019, or used to fulfill cleared capacity commitments prior to December 19, 2019, in its entirety.[93]

While the above approach is appropriate for most end-use customer locations registered as Demand Resources, utility-based residential load curtailment programs are more difficult to track. The sheer number and switching of individual residential customers that participate in utility-based curtailment programs make tracking the exemption based on specific residential customer locations impracticable. Thus, for purposes of utility-based residential load curtailment programs, PJM proposes to treat as exempt the total number of participating residential customer locations that were associated with a Demand Resource that cleared prior to the December 19, 2019 date.

To further effectuate the Commission's directive to exempt Demand Resources that cleared an RPM Auction prior to December 19, 2019, PJM proposes to apply the exemption to any end-use customers registered that support MWs cleared in any RPM Auction conducted prior to December 19, 2019.[94] Given that Capacity Market Sellers submit Sell Offers for Demand Resources into an RPM Auction before end-use customer registrations are finalized, certain Demand Resources that cleared an RPM Auction prior to December 19, 2019, may not yet have end-use customer locations that are linked to the registrations associated with that resource. PJM proposes to allow Capacity Market Sellers to link any end-use customer in the registrations that correspond with Demand Resources that cleared such auctions no later than 45 days prior to the BRA for the 2022/2023 Delivery Year. The requirement to submit the eligible registrations no later

[93] *See* proposed Tariff, Attachment DD, section 5.14(h)(7)(A).

[94] For 2020/2021 Delivery Year, this includes the BRA, First IA, and Second IA. For 2021/2022 Delivery Year, this includes the BRA and First IA.

than 45 days before the BRA ensures that all registrations will be on file sufficiently in advance of two other major, pre-auction Demand Resource deadlines for the 2022/2023 Delivery Year —submission of DR Sell Offer Plans and a seller's certification of whether the resource is a Capacity Resource with State Subsidy, both of which are due thirty days before the auction.[95] Thus, Capacity Market Sellers will understand the universe of end-use customer locations that qualify for the categorical Demand Resource exemption and will have at least fifteen days to compile Demand Resources in order to ensure the resource will not be subject to MOPR in the 2022/2023 BRA.

b. Applying the exemption to Energy Efficiency Resources

In order to participate in an RPM Auction, Energy Efficiency providers must submit a measurement and verification plan ("M&V Plan") identifying the Nominated Energy Efficiency Value along with a description on the methods and procedures for determining that value. The Nominated Energy Efficiency Value submitted in the M&V Plan is not by location, but rather through an aggregated total of all Energy Efficiency projects that were installed in a Zone or Sub-Zone during that installation period. Thus, whether a Sell Offer for an Energy Efficiency Resource should be subject to or is exempt from the MOPR should be determined in an aggregated manner as well. For purposes of the Energy Efficiency exemption, PJM proposes to exempt Sell Offers up to a determined MW quantity calculated for each installation period, Zone and Sub-Zone by using the greater of the latest approved post-installation measurement and verification report prior

[95] *See* proposed RAA, Schedule 6, section A(5); proposed Tariff, Attachment DD-1, section A(5).

to December 19, 2019, or the maximum MW cleared for a Delivery Year across all auctions conducted prior to December 19, 2019.[96]

Like the other categorical exemptions, PJM will retain a list of end-use customers and locations that qualify for the Demand Resource exemption, as well as a list of post-installation measurement and verification report for the Energy Efficiency exemption. Thus, it will be unnecessary for Capacity Market Sellers to notify PJM which end-use customer locations or Energy Efficiency Resources qualify for this exemption. Instead, PJM will provide a list of exempt end-use customer locations and Energy Efficiency Resources associated with the Capacity Market Seller that last registered such customer locations or submitted the post-installation measurement and verification report prior to December 19, 2019.[97] The Capacity Market Seller would then simply need to confirm whether those customer locations will continue to be included in sell offer lans through the existing pre-registration process. Similarly, the Capacity Market Seller would also simply confirm whether the Energy Efficiency Resources that are exempt from the MOPR will continue to be offered by the Capacity Market Seller.

F. PJM Will Exempt Certain Capacity Storage Resources from Being Subject to the MOPR.

1. Commission Directive

In the December 19 Order, the Commission directed PJM to include a limited exemption from the MOPR for certain Capacity Storage Resources that receive or are eligible to receive a State Subsidy. In particular, the Commission stated that Capacity

96 Proposed Tariff, Attachment DD, section 5.14(h)(7)(C).

97 Utility mass market programs register the number of customer locations that participate in their program. Therefore, PJM intends to exempt, as applicable, the number of such customer locations that were registered in the past based on a consistent time period as all other exempt customer locations. *See* Proposed Tariff, Attachment DD, section 5.14(h)(7)(A).

Storage Resources that qualify for a state-mandated or state-sponsored RPS and (a) have successfully cleared an annual or incremental capacity auction prior to December 19, 2019; (b) have an executed interconnection construction service agreement on or before December 19, 2019; or (c) have an unexecuted interconnection construction service agreement filed by PJM for the resource with the Commission on or before December 19, 2019, would be exempt from the MOPR.[98]

2. PJM Compliance Language

Finally, consistent with the December 19 Order, PJM proposes to include a categorically exempt Capacity Storage Resources[99] from the modified MOPR if one of the following three criteria are met: (a) has successfully cleared an RPM Auction prior to December 19, 2019; (b) is the subject of an interconnection service agreement or equivalent agreement[100] executed on or before December 19, 2019; or (c) is the subject of an unexecuted interconnection service agreement or equivalent agreement filed by PJM with the Commission on or before December 19, 2019, will be exempt from the MOPR.[101]

98 December 19 Order at P 202. While the Commission included the Capacity Storage Resource exemption with Demand Resources and Energy Efficiency Resources in the December 19 Order, PJM proposes to separate out the Capacity Storage Resource given the distinct qualifications for the exemption between the different resource types.

99 Capacity Storage Resource is defined as "any Energy Storage Resource that participates in the Reliability Pricing Model or is otherwise treated as capacity in PJM's markets such as through a Fixed Resource Requirement Capacity Plan." Tariff, Definitions C-D. This includes any resource that is capable of receiving electric energy from the grid and storing it for later injection to the grid, including pumped hydro.

100 WMPAs should also be included in this exemption, as it is another type of agreement that allows a generator that is interconnected to non-jurisdictional facilities to participate in PJM's markets, including the capacity market. Resources with a WMPA executed prior to December 19, 2019, reasonably expected to participate in the capacity market and are also not be subject to the MOPR, consistent with the December 19 Order.

101 *See* proposed Tariff, Attachment DD, section 5.14(h)(8).

Similar to the other categorical exemptions, it is appropriate to allow any Capacity Storage Resource that is the subject of any interconnection construction service agreement, interim interconnection service agreement, interconnection service agreement, or other similar interconnection agreement to qualify for the Capacity Storage Resource exemption. This is because interconnection service agreements, along with interim interconnection service agreements, appropriately exempts any Capacity Storage Resources where investment decisions were made prior to the December 19 Order. This is consistent with the Commission's rationale that Capacity Storage Resources that have an interconnection service agreement in place reasonably relied on prior Commission guidance in formulating their business plans.[102]

Given that PJM already has all information pertaining to which Capacity Storage Resources are eligible for this categorical exemption, it is unnecessary for Capacity Market Sellers of such resources to affirmatively elect this exemption. Instead, PJM intends to provide the relevant Capacity Market Sellers with a list of their Capacity Storage Resources that qualify for this exemption. The Capacity Market Sellers would then simply need to confirm whether they agree with the list of exempt Capacity Storage Resources.

G. Consistent with the December 19 Order, PJM Will Exempt Resources that Elect to Forego State Subsidies from Being Subject to the MOPR Through a Competitive Exemption.

1. Commission Directive

In the December 19 Order, the Commission directed PJM to include a competitive exemption for Capacity Market Sellers of Capacity Resources that elect to forgo the

102 December 19 Order at P 208.

receipt of any State Subsidy even if such resources are entitled to one.[103] Any eligible Capacity Market Seller that elects to forgo a State Subsidy for the relevant Delivery Year will be allowed to avoid being subject to the applicable MOPR Floor Offer Price.

2. PJM Compliance Language

a. Promising to forego State Subsidies

In accordance with the December 19 Order, PJM is including a competitive exemption for Capacity Market Sellers, other than Self-Supply Entities or new CT or CC resources that have not cleared an RPM Auction,[104] to certify that they will elect to forgo accepting any State Subsidy for the relevant Capacity Resource. This competitive exemption would only be available to Capacity Market Sellers that elect to forego accepting all applicable State Subsidies for a given resource. The election of the competitive exemption will allow Capacity Market Sellers of State Subsidized resources to offer below the default MOPR floor price.[105]

Capacity Market Sellers of Capacity Resources that generate RECs or equivalent credits may elect this competitive exemption if they certify that the credits will only be used and retired for voluntary obligations as opposed to state-mandated renewable portfolio standards.[106] Through this approach, Capacity Market Sellers may certify that

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103 December 19 Order at P 161.

104 *See* proposed Tariff, Attachment DD, section 5.14(h)(4). The competitive exemption is not available to New Entry Capacity Resources that are natural gas fired combined cycle or combustion turbine resources. *See* proposed Tariff, Attachment DD, section 5.14(h)(4).

105 Capacity Market Sellers of resources that generate RECs or equivalent credits may elect this competitive exemption if they can demonstrate, upon request, that the credits will only be used and retired for voluntary obligations as opposed to state-mandated renewable portfolio standards. Through this approach, Capacity Market Sellers that can ensure that RECs that are eligible for state sponsored RPS programs will not be used for state mandated compliance purposes can avoid being subject to the modified MOPR.

106 As further explained below, this option is only available if the Capacity Market Seller owns such resource in whole or all Capacity Market Sellers that jointly own or are a party to a bilateral transaction of the facilty unanimously elect the competitive exemption.

RECs that are eligible for state sponsored RPS programs will not be used for state mandated compliance purposes can avoid being subject to the modified MOPR.[107]

However, resources owned or contracted by Self-Supply Entities would not be eligible because any resource owned or contracted by a Self-Supply Entity (that is not otherwise exempt) is subject to the modified MOPR under the broad definition of State Subsidy and such entity cannot practically forgo the subsidy since it is derived from their business model. Further, consistent with the Commission's directive,[108] Capacity Market Sellers of CT and CC resources that are subject to the MOPR are not eligible for the competitive exemption.[109] Resources that are no longer entitled to a State Subsidy that nonetheless are deemed to be Capacity Resources with State Subsidy because they have not cleared an RPM Auction since they last received a State Subsidy also are not eligible for the competitive exemption and would be required to submit a Sell Offer in accordance with the MOPR.[110] To allow such resources to promise to forego a non-existent subsidy and offer at any price level would be contrary to the December 19 Order's directive that such resources should be subject to the MOPR upon the subsidy's sunset.[111] In addition, Capacity Market Sellers of a Jointly Owned Cross-Subsidized Capacity Resource or Capacity Resource with State Subsidy that is the subject of a bilateral transaction are

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107 To facilitate Capacity Market Seller of such resources election of the competitive exemption, PJM will modify the existing Generation Attribute Tracing System (i.e., "GATs") to ensure that any Capacity Market Sellers' self-imposed limitations on use of the RECs can be effectuated. In this way, REC generating resources that elect the competitive exemption can only be used for voluntary obligations and are not eligible to be retired for mandatory state RPS requirements in the GATs system.

108 *See* December 19 Order at P 161.

109 *See* proposed Tariff, Attachment DD, section 5.14(h)(4)(A).

110 *See* proposed Tariff, Attachment DD, section 5.14(h)(4)(A).

111 *See* December 19 Order at P 75 ("We further find that a capacity resource should be considered to be entitled to receive a State Subsidy if the resource previously received a State Subsidy, and has not cleared a capacity auction since that time.").

ineligible for the competitive exemption, unless all Capacity Market Sellers of Capacity Resources supported by the joint-owned facility unanimously elect to take the competitive exemption.[112] Unanimity is required because otherwise any owner that takes a State Subsidy can pass through the benefits to the other owners or parties—which is precisely the reason these Capacity Resources are considered Capacity Resources with State Subsidy and subject to the MOPR. Thus, allowing a Capacity Market Seller of a Jointly Owned Cross-Subsidized Capacity Resource or a Capacity Resource with State Subsidy that is the subject of a bilateral transaction to be eligible for the competitive exemption without unanimity of ownership would defeat the purpose of the MOPR.

Any eligible Capacity Market Seller that seeks to elect the competitive exemption will be required to certify that it will forego acceptance of all applicable State Subsidies for a given resource for the relevant Delivery Year. Such certification would be made no later than 30 days prior to the conduct of the relevant RPM Auction for each Delivery Year that the Capacity Market Seller wishes to elect the competitive exemption.[113] A Capacity Market Seller may elect the competitive exemption each individual Delivery Year that it will elect to forego the State Subsidy.

b. <u>Consequences of a Cleared Capacity Resource that accepts a State Subsidy after electing the competitive exemption</u>

Consistent with the Commission's compliance directive,[114] the consequence of a Capacity Market Seller accepting a State Subsidy after electing the competitive exemption depends on whether the resource electing the competitive exemption is a "new entry" resource which the market has yet to demonstrate a need for the resource at the

[112] *See* proposed Tariff, Attachment DD, section 5.14(h)(4)(A).

[113] *See* proposed Tariff, Attachment DD, section 5.14(h)(4)(A).

[114] *See* December 19 Order at P 162.

resource's costs or an "existing" resource.[115] Specifically, a Capacity Market Seller of a Cleared Capacity Resource with State Subsidy (i.e., an "existing" resource) that elects the competitive exemption, clears the auction, and then subsequently accepts a State Subsidy for that Delivery Year will not receive any RPM revenues for any part of that Delivery Year.[116] There is an exception to this rule by which a Capacity Market Seller may retain capacity revenues if it can demonstrate that the subject resource would have cleared in the relevant RPM Auction at or above an offer consistent with its resource-specific exception MOPR floor price.[117]

Regardless of whether the resource receives capacity revenues, it cleared the market and undertook a capacity obligation. Therefore, such resource would still be subject to all obligations associated with a committed Capacity Resource for that Delivery Year (e.g., must-offer requirements and requirement to perform during Performance Assessment Interval). At the same time, a Cleared Capacity Resource with State Subsidy that elects the competitive exemption but accepts a State Subsidy for the relevant Delivery Year will still be eligible to receive bonus payments for over performance during a Performance Assessment Interval (and conversely would remain subject to Non-Performance Charges for under-performance).[118] This is appropriate because the ultimate goal during a Performance Assessment Interval is to ensure sufficient generation in times of system stress—regardless of whether the Capacity Market Seller of a resource accepted a State Subsidy. Further, this provides the

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115 In addition to the financial consequences outlined herein, Capacity Market Sellers that violate the competitive exemption by accepting a subsidy will also face the consequence of being in violation of the Tariff and potential referral to the Commission's Office of Enforcement.

116 *See* proposed Tariff, Attachment DD, section 5.14(h)(4)(B)(ii).

117 *See* proposed Tariff, Attachment DD, section 5.14(h)(4)(B)(ii).

118 *See* proposed Tariff, Attachment DD, section 5.14(h)(4)(B)(ii).

appropriate balance between penalizing units that elect the competitive exemption and then take a subsidy with the fact that the unit can still provide needed MWs during times of a system emergency and should be eligible to collect bonus payments for any over-performance in that instance.

These same outcomes apply to an unsubsidized resource that clears an RPM Auction, undertakes a capacity commitment, and then subsequently becomes entitled to a State Subsidy and accepts such subsidy in the relevant Delivery Year. Just as for those Capacity Market Sellers of resources that promised to forego receiving State Subsidies, Capacity Market Sellers of unsubsidized resources that receive State Subsidies must forfeit all their capacity revenues associated with the Capacity Resource for that Delivery Year, unless they can demonstrate that the resource would have cleared on a resource-specific offer. And, the resource retains all its capacity obligations and responsibilities,[119] regardless of whether it receives the revenues.[120]

These rules also apply to Jointly Owned Cross-Subsidized Capacity Resources and Capacity Resources supported by bilateral transactions in either of the two circumstances described above. But the exposure is greater for these Capacity Market Sellers, as they must also be concerned that no MWs from the supporting facility receive any State Subsidy during the Delivery Year. If that happens, then all Capacity Market Sellers of the Jointly Owned Cross-Subsidized Capacity Resource or of the bilateral Capacity Resource must return their capacity revenues—even if that Capacity Resource did not receive any State Subsidy—unless the resource would have cleared on an offer

[119] The Capacity Market Seller may purchase replacement capacity to fulfill its obligations.

[120] *See* proposed Tariff, Attachment DD, section 5.14(h)(4)(B)(ii).

consistent with its resource-specific exception MOPR floor price.[121] Indeed, if one entity accepts a State Subsidy, then all Capacity Market Sellers of Capacity Resources supported by the same facility will be required to return the associated capacity revenues. To allow otherwise would provide a loophole through which the owners of a facility can receive the best of both worlds: an unmitigated offer into the capacity market, plus the benefits of a State Subsidy.

Any capacity market revenues forfeited will be returned to the load that bears the cost of the subsidy collected by the resource, and if PJM is unable to identify the subsidizing load (e.g., in the case of a REC being the offending subsidy), then PJM shall return the forfeited revenues to across all load in the PJM Region that is not under an FRR plan.[122] That is, PJM will refund any collected revenues back to the load in the state(s) that paid the subsidy. This is appropriate because the load that pays for the subsidy and absorbs the costs of such subsidy should be able to receive the benefit of not paying the RPM clearing price when the resource accepts the State Subsidy. However, for other resources where PJM cannot identify the load that paid for the subsidy, PJM would refund any collected revenues across all load in the load zone or RTO.[123]

c. <u>Consequences of a New Entry Capacity Resource that accepts a State Subsidy after electing the competitive exemption</u>

The consequence of a New Entry Capacity Resource accepting a subsidy in its first Delivery Year after committing to forego receiving any State Subsidies via the

121 *See* proposed Tariff, Attachment DD, section 5.14(h)(4)(B)(ii).

122 Proposed Tariff, Attachment DD, section 5.14(h)(4)(B)(iii).

123 Proposed Tariff, Attachment DD, section 5.14(h)(4)(B)(iii).

competitive exemption is different. As directed by the December 19 Order,[124] such resource will no longer be allowed to participate in any RPM Auction or be eligible to be used as replacement capacity for a period of 20 years starting from June 1 of the Delivery Year[125] after the Capacity Market Seller accepts such State Subsidy.[126] However, battery storage resources will be restricted from participating in RPM for a period of 15 years, consistent with PJM's gross CONE analysis[127] and the December 19 Order.[128]

Consistent with the treatment of a Cleared Capacity Resource that accepts a State Subsidy in the year it cleared, such committed New Entry Capacity Resource will not receive RPM revenues for any part of the Delivery Year that it accepted a State Subsidy, regardless of whether such resource would have cleared at its resource-specific MOPR Floor Offer Price.[129] Further, the resource will remain subject to all the obligations of a committed Capacity Resource (e.g., must-offer requirements and requirement to perform during Performance Assessment Interval, as well as remain eligible for bonus payments and Non-Performance Charges). However, in the event that the resource in such circumstance has capacity commitments for future Delivery Years (which is possible given the forward nature of RPM), the resource must honor its commitment to provide

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124 December 19 Order at P 162.

125 For Demand Resources, the supporting end-use customer location will no longer be allowed to participate in RPM, not the entire zonal resource.

126 Proposed Tariff, Attachment DD, section 5.14(h)(4)(B)(i). During such 20-year period, the resource will be allowed to provide capacity as part of an FRR Alternative Plan and may collect bonus payments under Tariff, Attachment DD, section 10A associated with performance during a Performance Assessment Interval. Proposed Tariff, Attachment DD, section 5.14(h)(4)(B)(i).

127 *See* Affidavit of Adam J. Keech on Behalf of PJM Interconnection, L.L.C. ¶ 15 ("Keech Aff.") ("[B]ased on an evaluation of asset life for battery energy storage resources published in several studies (and summarized by NREL), PJM determined that the assumed applicable asset life for battery storage resource should be 15 years."). The Keech Affidavit is Attachment E to this filing.

128 *See* December 19 Order at P 162 n.313.

129 Proposed Tariff, Attachment DD, section 5.14(h)(4)(B)(i).

the promised capacity, and the Capacity Market Seller may retain the capacity revenues for those Delivery Years so long as the Capacity Market Seller does not also receive State Subsidies in those years as well.

The same consequence generally applies for a Capacity Resource that was not entitled to a State Subsidy at the time it first cleared an RPM Auction (meaning it could not, and had no reason to, elect the competitive exemption) and then elected to accept a State Subsidy prior to the end of that Delivery Year.[130] In other words, a new resource that is not entitled to a State Subsidy that accepts such subsidy at any time before it fulfills its capacity commitment for that first Delivery Year will be prohibited from participating in RPM for a period of 20 years starting from June 1 of the Delivery Year after the Capacity Market Seller accepts such State Subsidy and must return any capacity revenues received in that first Delivery Year.[131] Notwithstanding, the Capacity Market Seller must honor its existing capacity commitments (i.e., maintain all its obligations and responsibilities for its first Delivery Year and any subsequent Delivery Year for which it secured a capacity commitment prior to accepting a State Subsidy) and may retain Capacity Market revenues for its future commitments to the extent it does not collect State Subsidies for providing capacity in those future Delivery Years.[132]

As above, Jointly Owned Cross-Subsidized Capacity Resources and Capacity Resources supported by bilateral transactions may also be subject to this rule if their Capacity Market Seller or any other entity associated with the energy output of the

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[130] Proposed Tariff, Attachment DD, section 5.14(h)(4)(B)(i).

[131] This is consistent with the Commission's directive that the resource may not participate in the capacity market from the point it elects to accept a state Subsidy. *See* December 19 Order at P 162.

[132] Proposed Tariff, Attachment DD, section 5.14(h)(4)(B)(i).

underlying facility receives a State Subsidy before or during the resource's first Delivery Year with a capacity commitment. In such a case, all Capacity Resources supported by the same facility will be prohibited from participating in RPM for a period of 20 years starting from June 1 of the Delivery Year after which the State Subsidy was received.[133] Likewise, the Capacity Market Sellers of such resources must return any capacity revenues received for the applicable Delivery Year.

The same rule for refunding to load any returned capacity revenues would apply, with the revenues returned to the subsidizing load or, if PJM cannot identify such load, the monies would be refunded across the non-FRR portions of load in the PJM Region.[134]

H. New Entry Capacity Resources Will Have MOPR Floor Offer Prices Based on the Net Cost of New Entry.

1. Commission Directive

In the December 19 Order, the Commission found that the "default offer price floor for certain resources that have not previously cleared the capacity market at Net CONE for each resource type," should be set at "100 percent of Net CONE."[135] Further, the Commission held that "new State-Subsidized Resources must first clear the capacity auction subject to the default offer price floor appropriate to a new resource," before the resource may be considered "existing" and offered in at a level below its CONE.[136]

With regard to the default floor prices, the December 19 Order directed PJM "to use resource-type specific Net CONE values for resources that have not previously

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133 Proposed Tariff, Attachment DD, section 5.14(h)(4)(B)(i).

134 Proposed Tariff, Attachment DD, section 5.14(h)(4)(B)(iii).

135 December 19 Order at P 138.

136 December 19 Order at P 141.

cleared a capacity auction,"[137] "regardless of whether it is above the demand curve starting price."[138] PJM must, for each default Net CONE value, "provide additional explanation on how it calculated each of the proposed values on compliance, including workbooks and formulas, as appropriate."[139] The Commission also adopted PJM's proposal to update the default values "annually and as part of PJM's quadrennial review of its demand curve and CONE values."[140]

2. *PJM Compliance Language*

As directed, PJM is updating its MOPR provisions to specify default MOPR Floor Offer Prices to New Entry Capacity Resources (i.e., Capacity Resources with State Subsidy and new CTs and new CCs that have never cleared an RPM Auction) that are based on the costs of constructing a new facility—CONE.[141] As such values are based on the "net" CONE values for each resource type. PJM must first determine a default "gross" CONE value and then subtract, based on Zone, the estimate of that resource type's net E&AS revenues. Mr. Adam J. Keech, Vice President, Market Operations, explains in the affidavit attached to this compliance filing how PJM developed the default MOPR Floor Offer Prices, as well as the methodology for the E&AS revenues.[142] Consistent with the December 19 Order, PJM will post updated default New Entry

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[137] December 19 Order at P 143.

[138] December 19 Order at P 142.

[139] December 19 Order at P 143.

[140] December 19 Order at P 143.

[141] *See* proposed Tariff, Attachment DD, section 5.14(h)(2)(A). PJM and stakeholders will revisit these values as part of the quadrennial review of the VRR Curve and the CONE value supporting it. Tariff, Attachment DD, section 5.10(iii).

[142] Keech Aff. ¶ 5.

Capacity Resource MOPR Floor Offer Prices 150 days before the applicable RPM Auction.[143]

a. Gross CONE values

PJM determined gross CONE values for various resource types to use in RPM Auctions for the 2022/2023 Delivery Year and plans to state these initial gross CONE values in the Tariff.[144] The gross CONE values reflect an estimate of the "nominal-levelized" annual cost to construct and develop a new greenfield construction for the resource type.[145] As directed by the December 19 Order,[146] Mr. Keech also provides additional explanation and supporting documentation for these gross CONE values.[147]

As Mr. Keech explains, PJM developed these values based on review of cost data from sources such as the U.S. Energy Information Administration ("EIA") and Lazard. Each of these sources is publicly available.[148] PJM used the EIA data "for all [of] the technologies, except the solar [photovoltaic ("PV")] (fixed), combustion turbine, combined cycle and demand response resource types,"[149] as the EIA data "represents the

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143 *See* proposed Tariff, Attachment DD, section 5.14(h)(2)(A).

144 *See* proposed Tariff, Attachment DD, section 5.14(h)(2)(A).

145 Keech Aff. ¶ 5.

146 December 19 Order at P 143.

147 *See generally* Keech Aff. Mr. Keech also separately provides the installed capital cost ("Capex"), fixed operating and maintenance cost ("FOM") reviewed from different sources of data, the actual values used for each resource in developing CONE, E&AS, and Net CONE in both Installed Capacity ("ICAP") and Unforced Capacity ("UCAP") basis. The worksheet also shows the EFORd values for conventional resources and ICAP capacity factor for solar, wind, and battery energy storage resources used to convert Net CONE from nameplate to ICAP. Also shown in the worksheet are the individual zonal default MOPR Floor Offer Price for each resource. Keech Aff. ¶ 6.

148 *Lazard's Levelized Cost of Energy Analysis–Version 13.0*, Lazard (November 2019), https://www.lazard.com/media/451086/lazards-levelized-cost-of-energy-version-130-vf.pdf; U.S. Energy Information Administration, *Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies* (February 2020), https://www.eia.gov/analysis/studies/powerplants/capitalcost/.

149 Keech Aff. ¶ 11.

most recent (published in February 2020) publicly available source and is well-documented."[150] "Further, the EIA data includes Capex and FOM values for nuclear, coal, solar photovoltaic [] (tracking type), onshore wind, offshore wind, and battery energy storage technologies,"[151] which provides transparency into the Gross CONE determination. The CT and CC gross CONE values are the same the values the Commission approved in the 2018 quadrennial review proceeding.[152]

Moreover, PJM has based its calculations on publicly available data as this has the benefit of providing transparency and a clear independent source for the values presented. Indeed, Mr. Keech explains that, with access to a pro forma analysis tool, any person "with access to a pro forma analysis tool can use the Capex and FOM data included in the workbook in Appendix A (which is all from publicly available sources), plus the financial assumptions provided by PJM to reproduce the CONE values PJM calculated."[153]

To determine the gross CONE values, Mr. Keech explains that PJM employed the same financial assumptions used to determine the CT and CC values in the 2018 quadrennial review proceeding.[154] However, in determining the values for wind and solar resources, PJM accounted for a federal investment tax credit ("ITC"), under which up to 30% the investment is a direct credit against federal income tax in the first year. As a result, the ITC approximately reduces gross CONE value by 30%, and PJM assumed that

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150 Keech Aff. ¶ 11.

151 Keech Aff. ¶ 11.

152 *See PJM Interconnection, L.L.C.*, 167 FERC ¶ 61,029 (2019).

153 Keech Aff. ¶ 20.

154 Keech Aff. ¶¶ 15 & Table 2.

both solar and wind projects would qualify for the maximum. Thus, the gross CONE values for all wind and solar resource types reflects a 30% reduction in cost.[155]

In advance of each BRA, PJM will adjust the Tariff-stated gross CONE values for CT and CC resources for subsequent Delivery Years using the same Applicable BLS Composite Index mechanism for adjusting the CONE value on which the Variable Resource Requirement ("VRR") Curve is based.[156] As prescribed by the Tariff, this index is "a composite of the BLS Quarterly Census of Employment and Wages for Utility System Construction (weighted 20%), the BLS Producer Price Index for Construction Materials and Components (weighted 55%), and the BLS Producer Price Index Turbines and Turbine Generator Sets (weighted 25%)."[157] As Mr. Keech explains, for all other resource types, PJM will replace the "BLS Producer Price Index Turbines and Turbine Generator Sets" index with the BLS's "Producer Price Index for Goods Less Food and Energy, Private Capital Equipment" index, with no change to the relative weight of each index.[158] PJM proposes to rely on the Turbines index for combustion turbine and combined cycle resources only because "they are heavily dependent on that specific technology." By contrast, the other resource types "employ a wide range of equipment, [and] the broad index of Private Capital Equipment . . . is more appropriate to capture annual price changes across the industry."[159]

After adjusting the values using the applicable index, PJM will further adjust the values to account for continued application of bonus depreciation, consistent with the

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155 Keech Aff. ¶ 18.

156 Proposed Tariff, Attachment DD, section 5.14(h)(2)(A).

157 Tariff, Attachment DD, section 5.10(a)(iv)(B)(1).

158 *See* Keech Aff. ¶ 22.

159 *See* Keech Aff. ¶ 22.

adjustments to the VRR Curve's CONE value.[160] PJM will use "a factor of 1.022 for nuclear, coal, combustion turbine, and combine cycle resource types or 1.01 for solar, wind, and storage resource types to reflect the annual decline in bonus depreciation scheduled under federal corporate tax law."[161] Mr. Keech explains that "[t]he different adjustment factors reflect the different periods over which the tax laws permit the facilities to be depreciated," as nuclear, coal, combustion turbine, and combine cycle resource types are depreciated 15 years, while solar, wind, and storage resources are depreciated over five years.[162] The lower adjustment factor for solar, wind, and storage reflects the quicker recovery of the balance of bonus depreciation.

Consistent with existing practice, PJM will post these adjusted values on its website along with other relevant auction parameters.

Notwithstanding, PJM will not adjust the values for load-backed Demand Resources or for Energy Efficiency Resources.[163] No index-based adjustment is required for the load-backed Demand Resource MOPR Floor Offer Prices because there will be no Tariff-stated value to adjust. Rather, the default New Entry MOPR Floor Offer Prices for load-backed Demand Resources will be recalculated prior to each BRA and "separately determined for each Locational Deliverability Area as the MW-weighted average offer price of load-backed Demand Resources from the most recent three Base Residual Auctions."[164] To determine the MW-weighted average offer price, PJM will use "the portion of each Demand Resource Sell Offer that is supported by end-use customer

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160 *See* Tariff, Attachment DD, section 5.10(a)(iv)(B).

161 Proposed Tariff, Attachment DD, section 5.14(h)(2)(A).

162 Keech Aff. ¶ 23.

163 Proposed Tariff, Attachment DD, section 5.14(h)(2)(A).

164 Proposed Tariff, Attachment DD, section 5.14(h)(2)(A).

locations providing demand response through load reductions, as specified in the registrations provided during the pre-registration process for such Base Residual Auctions."[165] This will ease administrative burdens for Capacity Market Sellers of Demand Resource by allowing one Sell Offer for both generation-backed and load-backed Demand Resource if the Demand Resource does not receive or is not eligible to receive a State Subsidy.[166] To illustrate what the MOPR Floor Offer Prices may look like for new load-backed Demand Resources, below is a table showing PJM's preliminary determinations for the MOPR Floor Offer Prices for the 2022/2023 Delivery Year, based on the three-year historical average offer prices for Demand Resources, by LDA.

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165 Proposed Tariff, Attachment DD, section 5.14(h)(2)(A).

166 Demand Resources that receive or are entitled to receive a State Subsidy will be required to submit separate Sell Offers for generation-backed Demand Resources and load-backed Demand Resources given the different default MOPR floor price.

Table 3: Preliminary Three-Year Historical Average DR Offer Prices, By LDA

LDA (Rest Of)	Average
ATSI	$47.07
ATSI-CLEVELAND	$47.54
BGE	$66.81
COMED	$60.55
DAY	$43.20
DEOK	$43.15
DPL-SOUTH	$63.68
EMAAC	$58.18
MAAC	$55.12
PEPCO	$49.56
PPL	$58.57
PSEG	$57.10
PS-NORTH	$52.60
RTO	$49.73
Entire RTO	**$53.32**

Based on these values, the MOPR Floor Offer Price for Planned Demand Resources will range from $43.15.79 to $66.81, depending on the LDA in which the resource is located.[167]

Because the Energy Efficiency Resource MOPR Floor Offer Price is not solely cost based, but rather reflects costs as well as energy and dollar savings, an index-based adjustment is inappropriate. PJM proposes that the Energy Efficiency Resource MOPR Floor Offer Price will remain static between quadrennial reviews. To develop the Energy Efficiency Resource MOPR Floor Offer Price, PJM asked The Brattle Group ("Brattle") and Sargent & Lundy ("S&L") for assistance.[168] As described in the Brattle Report, the net CONE value is an estimate of "the total economic costs of the [Energy Efficiency] programs minus all (non-capacity) cost savings," and considers the cost to participate in

[167] *See* Keech Aff. ¶ 28.

[168] *See* Affidavit of Samuel A. Newell, John M. Hagerty and Sang H. Gang on Behalf of PJM Interconnection, L.L.C. ("Brattle Affidavit").

the capacity market and the cost savings from reduced wholesale energy purchases and from reduced infrastructure investment.[169] To estimate net CONE, Brattle evaluated the energy efficiency programs in four utility regions. For each program, Brattle "subtract[ed] the estimated wholesale energy savings and [transmission and distribution] savings from the Gross CONE."[170] Then, to arrive at the generic default net CONE value of $64/MW-Day (ICAP),[171] Brattle determined the capacity-weighted average of each program's net CONE.[172]

For generation-backed Demand Resources, the default MOPR Floor Offer Price considers the costs and offsets using a similar methodology as interconnected "front of the meter" generation. PJM is using Lazard[173] data for the generation-backed demand response resource type, which include complete cost data for a small (0.5 MW) diesel generator.[174] Lazard is used in this case because the diesel resource provided in the EIA data was approximately 20 MW in size, which PJM believed to be too large to be representative of a behind-the-meter generator.[175]

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169 *Gross Avoidable Cost Rates for Existing Generation and Net Cost of New Entry for New Energy Efficiency*, The Brattle Group and Sargent & Lundy, 27 (March 17, 2020) ("Brattle Report"). The Brattle Report is included with the Brattle Affidavit in Attachment D to this filing.

170 Brattle Report at 29. Brattle calculated the ICAP savings by grossing up the MW of reported program savings "by the assumed losses during peak periods," and then grossed up that value by the Forecast Pool Requirement to determine the UCAP savings. *Id.*.

171 Brattle Report at iv, Table 3 & 31, Table 15.

172 Brattle Report at iv, 29.

173 *Lazard's Levelized Cost of Energy Analysis – Version 11.0*, Lazard (November 2017) https://www.lazard.com/media/450337/lazard-levelized-cost-of-energy-version-110.pdf.

174 Keech Aff. ¶ 27.

175 Keech Aff. ¶ 27.

As directed by the December 19 Order, and consistent with longstanding practice, PJM will review and re-evaluate the Tariff-stated default values as part of the quadrennial review of the VRR Curve and CONE values.[176]

b. Energy and ancillary services revenues offset

To determine the "net" cost of new entry, the gross CONE values must be reduced to recognize the net revenues a resource can reasonably expect to earn in PJM by providing energy and ancillary services. Because each resource type participates in the market differently, based on the characteristics inherent to the resource (e.g., solar and wind can only run when the sun is shining or the wind is blowing), PJM will employ different approaches for determining a resource type's expected net E&AS revenues, by transmission Zone. While the exact methodology may differ, each approach is based on the following fundamental principles: when is the resource likely to run; what is the locational marginal pricing ("LMP") at that time; what ancillary service revenues can be expected; and what are the resource's applicable costs of providing energy and ancillary services that should be subtracted from such revenues. To capture costs to be recovered through energy market offers, PJM will consider among other costs "Fuel Costs, Maintenance Adders and Operating Costs, as applicable, pursuant to Operating Agreement, Schedule 2."[177]

While Mr. Keech provides a detailed description of how PJM will calculate the revenue offset for each resource type,[178] a summary of each approach for determining energy market revenues is provided below.

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176 Proposed Tariff, Attachment DD, section 5.14(h)(2)(A).

177 Proposed Tariff, Attachment DD, section 5.14(h)(2)(A).

178 *See* Keech Aff. ¶ 21.

For coal, CC, CT, and storage resource types, PJM will perform a simulated dispatch for each type, using the applicable reference resource and when that resource type is expected to run, based on the cost of the resource and its characteristics. In the simulated dispatch, PJM will assume that the resource can produce its nameplate capability during the assumed dispatch period and use that information, in addition to its variable cost and historic LMPs, to determine the net E&AS revenues for the resource over the prior three calendar years. Thus, for storage resources, PJM will assume a Capacity Storage Resource to be "dispatched for the four hours with the highest LMP of a daily twenty-four hour period,"[179] while in the coal simulated dispatch, PJM will assume that a coal unit is "committed day-ahead in profitable blocks of at least eight hours."[180] For CTs and CCs, PJM will use the same simulated dispatch parameters currently in the Tariff for these resource types and which are currently used in determining the applicable default MOPR Floor Offer Prices.[181] After determining energy market revenues, PJM will subtract the cost specific to each resource type to generate energy, based on the resource's parameters.

For solar and onshore wind, PJM has developed a model for each type that has determined based on historical data when that resource type has run over the past three years across the RTO and the applicable zonal LMPs. PJM will determine the energy market revenues "by multiplying the [solar or] wind output level of each hour by the real-

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179 Proposed Tariff, Attachment DD, section 5.14(h)(2)(A)(ix).

180 Proposed Tariff, Attachment DD, section 5.14(h)(2)(A)(ii).

181 *Compare* Proposed Tariff, Attachment DD, sections 5.14(h)(2)(A)(iii) & (iv), *with* Tariff, Attachment DD, sections 5.10(a)(v) & 5.14(h)(3). While PJM is not changing the current Tariff's simulated dispatch parameter for combined cycle resource, PJM is updating the reference resource parameters for combined cycle resources to match those determined in the 2018 quadrennial review. *See* Proposed Tariff, Attachment DD, section 5.14(h)(2)(A)(iv).

time zonal LMP applicable to such hour with this product summed across all of the hours of an annual period."[182] PJM has developed separate models for "fixed" solar and "tracking" solar resource types.[183]

For nuclear resource type, PJM will determine energy market revenues by multiplying the "annual average zonal LMP" against "the annual energy output produced at the class average equivalent availability factor," and the currently class average equivalent availability factor for nuclear is about 94%. After determining energy market revenues, PJM will subtract the cost specific to each resource type to generate energy, based on the resource's parameters.

For the offshore wind resource type, PJM will determine energy market revenues by multiplying the "average annual zonal real-time LMP" against "an assumed annual capacity factor of 45%."[184]

For ancillary services revenues, Mr. Keech explains that PJM is assuming annual ancillary service revenues of $3,350/MW-year for all resource types, except combustion turbines and generation-backed Demand Resources.[185] This figure is reasonable for wind and solar resources as well, as it is consistent with a number of recent reactive rate filings of this resource type, and the relatively small overall impact of this annual dollar value as compared to annual energy market revenues.[186] As determined in the quadrennial review proceeding, combustion turbines are assumed to earn $2,199/MW-year in ancillary

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182 Proposed Tariff, Attachment DD, section 5.14(h)(2)(A)(vi).

183 Proposed Tariff, Attachment DD, section 5.14(h)(2)(A)(v). "Tracking" solar PV resources are those with the capability of the solar panels to move and "track" the sun, while "fixed" solar PV resources lack such capability.

184 Proposed Tariff, Attachment DD, section 5.14(h)(2)(A)(vii).

185 Keech Aff. ¶ 21; *see, e.g.*, proposed Tariff, Attachment DD, sections 5.14(h)(2)(A)(i) through (ix).

186 *See* Keech Aff. ¶ 21.

services revenues.[187] Given that Demand Resources generally participate only as Emergency only resources, they do not earn measureable amounts of energy and ancillary services revenues as a resource class, so the presumption of $0/MW-year in energy and ancillary services revenues is appropriate for use in the default MOPR Floor Offer Price for Demand Resources.[188]

c. Net CONE values, i.e., default MOPR Floor Offer Prices

The MOPR Floor Offer Prices for all New Entry Capacity Resource types will be the net CONE values. PJM does not propose any discounting from those values. That is, the applicable floor price will be 100% of the net CONE for each resource type. This is a change from the current-effective MOPR, which sets the default floor price for new CTs and CCs at 90% of their net CONE value.[189] However, with the expansion of the MOPR to apply to resources of all types, such discounting would not be reasonable and could be unduly discriminatory. Specifically, although differing views are certainly valid on this issue, to the extent the Commission is seeking consistent resource-neutral offer floors going forward, the maintenance of separate offer floors based on differing percentages of net CONE appears inconsistent with that goal.

Based on the default gross CONE values and in accordance with the proposed E&AS offset methodologies, below in Table 1, PJM is providing illustrative default MOPR Floor Offer Prices (at net CONE). These values are illustrative only, as they are based on an "average Zonal E&AS revenue offset," while the actual Net CONE values will vary by Zone to reflect the revenue offset for that Zone. The actual zonal default

[187] *See* Tariff, Attachment DD, section 5.10(a)(v)(A).

[188] *See* Keech Aff. ¶ 27.

[189] *See* Tariff, Attachment DD, section 5.14(h)(4).

MOPR Floor Offer Prices proposed by PJM are shown in the workbook appended to Mr. Keech's affidavit.

Table 1: Illustrative Estimated Average New Entry Default MOPR Floor Offer Prices

	Illustrative Default MOPR Floor Offer Prices		
Planned Resource Type	**Gross CONE (Cost of New Entry) \$/MW-day (Nameplate)**	**Estimated Average Zonal E&AS Revenue Offset \$/MW-day (Nameplate)**	**Illustrative MOPR Floor Offer Prices net of E&AS Revenues \$/ICAP MW-day**
Nuclear	\$2,000	\$517	\$1,483
Coal	\$1,068	\$43	\$1,025
Combined Cycle	\$320	\$168	\$152
Combustion Turbine	\$294	\$48	\$246
Solar PV (Tracking)	\$290	\$185	\$175
Solar PV (Fixed)	\$271	\$117	\$367
Onshore Wind	\$420	\$240	\$1,023
Offshore Wind	\$1,155	\$337	\$3,146
Battery Energy Storage	\$532	\$116	\$1,040
Demand Response (Generation-backed)	\$254	\$0	\$254

Because Sell Offers are based on the megawatt quantity of energy that the resource can reliably contribute during peak hours, the intermittent nature of wind and solar resources requires their nameplate capacity to be discounted to determine ICAP. Accordingly, PJM has adjusted the net CONE values, which are expressed in dollars per

ICAP MW-day, to reflect the expected average output levels (based on PJM's experience) for fixed Solar PV, tracking Solar PV, Onshore Wind, and Offshore Wind down to 42.0%, 60%, 17.6%, and 26.0%, respectively, of the nameplate rating of these resource types.[190]

PJM is not proposing to provide default MOPR Floor Offer Price (i.e., default net CONE) values for those resource types for which PJM is unable to determine a default CONE value—for hydroelectric resources and for resources whose primary purpose is not generating energy. Any Capacity Resource that does not have an associated default CONE value will be required to submit a resource-specific exception.[191] In the event a Capacity Market Seller of a resource with no default CONE value fails to submit a resource-specific exception in accordance with the procedures in the Tariff and PJM Manuals, PJM will consider such Sell Offer as incomplete and reject the offer, preventing the resource from clearing the relevant RPM Auction.[192] Given that hydroelectric facilities are inherently site-specific, there is no "generic" facility from which PJM can derive a default value. For non-primary purpose resources, PJM simply lacks the data and experience with the costs to build these various facilities.[193] As PJM gains more

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190 *See Class Average Capacity Factors: Wind and Solar Resources*, PJM Interconnection, L.L.C. (June 4, 2017), https://www.pjm.com/-/media/planning/res-adeq/class-averagewind-capacity-factors.ashx?la=en. Capacity Market Sellers may request resource-specific capacity factors to determine the Installed Capacity of their solar or wind resource. *See* PJM Manual 21: *Rules and Procedures for Determination of Generating Capability*, Revision: 14 at Appendix B (Calculating Capacity Values for Wind and Solar Capacity Resources) (July 25, 2019) (detailing how to calculate resource-specific capacity factors for wind and solar resources). *See also* Keech Aff. ¶ 8.

191 *See* proposed Tariff, Attachment DD, section 5.14(h)(2)(A).

192 *See* proposed Tariff, Attachment DD, section 5.14(h)(2)(A).

193 There are only two resources whose primary purpose is not electric production currently in the interconnection queue, and PJM is aware of only twelve such resources that currently participate in PJM's capacity market.

experience with these types of resources, PJM may be able to provide a default value in the future through a separate Federal Power Act ("FPA") section 205[194] filing.

I. Cleared Capacity Resources with State Subsidy Will Have MOPR Floor Offer Prices Based on the Resource's ACR.

1. Commission Directive

In the December 19 Order, the Commission found that "the default offer price floor for existing resources [should be set] at the resource-type specific Net ACR,"[195] a value that "estimates how much revenue the resource requires (in excess of its energy and ancillary service revenue) to provide capacity in the given year."[196] The Commission directed PJM to develop and support new values on compliance and "to develop a process to ensure all the data used in the calculation is updated annually."[197]

2. PJM Compliance Language

Consistent with the December 19 Order, PJM is providing that the MOPR will apply to Cleared Capacity Resources with State Subsidy and that the applicable MOPR Floor Offer Prices for such resources will be based on the resource's going-forward costs, i.e., ACR.[198] The Capacity Market Seller may elect to use a resource-type default ACR or a resource-specific cost rate. Just like for new entry resources, PJM proposes to include in the Tariff default gross going-forward cost values for existing generation resources, and PJM will annually adjust those values using the same the 10-year average Handy-Whitman Index as used in determining the resource-specific ACR-based offer

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194 16 U.S.C. § 824d.

195 December 19 Order at P 148.

196 December 19 Order at P 148.

197 December 19 Order at P 149.

198 *See* proposed Tariff, Attachment DD, section 5.14(h)(2)(B).

caps pursuant to Tariff, AtFtachment DD, section 6.8.[199] As stated there, this index is used "to account for expected inflation from the time interval between the submission of the Sell Offer and the commencement of the Delivery Year."[200] To clarify, PJM will be using the 10-year average Handy-Whitman Index to scale ACR values while it will use a different index, the Applicable BLS Composite Index, to scale CONE values. This difference is because the BLS index includes scaling for construction costs that are relevant to CONE values and not to ACR values. ACR values are only subject to changes in things like inflation and equipment costs, not construction costs.[201]

To determine the applicable default MOPR Floor Offer Prices, PJM will need to reduce the gross ACRs by expected net E&AS markets revenues. As directed by the December 19 Order, PJM will determine an average value for each resource type, by transmission zone,[202] and such determination will account for revenues net of a number of various costs including major maintenance (i.e., Maintenance Adders), as applicable, and Fuel Costs.[203] The adjusted default values will be posted on its website in advance of each RPM Auction.[204]

PJM asked Brattle and S&L to determine the gross ACRs for each resource type; the results of which are detailed in the Brattle Report, along with a description of the

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199 *See* Tariff, Attachment DD, section 6.8(a) (Adjustment Factor).

200 Tariff, Attachment DD, section 6.8(a) (Adjustment Factor).

201 Keech Aff. ¶ 33.

202 *See* December 19 Order at P 154. While the December 19 Order stated that the default values should use zonal revenue estimates, PJM agrees with the Market Monitor that the default Gross ACR values should be determined using default cost values for the applicable resource type, but to arrive at the net ACRs, resource-specific E&AS offset values should be used. Request for Clarification of the Independent Market Monitor for PJM, Docket Nos. EL16-49-000, et al., at 3-4 (Jan. 17, 2020) ("Market Monitor Clarification Request"). PJM would be willing to implement such a change on compliance.

203 *See* Proposed Tariff, Attachment DD, section 5.14(h)(2)(B).

204 *See* Proposed Tariff, Attachment DD, section 5.14(h)(2)(B).

analysis and methodology employed.[205] Brattle and PJM consulted to ensure that "all avoidable costs to operate the resource for another year."[206] Brattle's approach "aligns with" the Tariff-based approach for determining ACR,[207] but omitted "the Capacity Performance Quantifiable Risk (CPQR) premium nor the investment described as a part of Avoidable Project Investment Recovery Rate (APIR) for the purposes of setting the default offer floor prices."[208] Following prescriptions in Operating Agreement, Schedule 2 and the Tariff, Attachment DD, section 6.8, Brattle included in its gross ACR analysis only those costs that may not be included in a resource's cost-based offers into the energy and ancillary services markets.[209]

The Brattle Report explains how the gross ACR for each resource was determined. For each resource type, Brattle determined the characteristics of a "representative plant" that is widely representative of the costs of most of the fleet. Using publicly available data, Brattle developed ACRs for these resources and then checked them against cost estimates in S&L's proprietary and confidential database.[210] The resulting Brattle-determined default gross ACR values, plus the values for load-backed Demand Resources and Energy Efficiency Resources, are shown in the table below, which is also stated in the Tariff.

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205 The Brattle Report provides the additional explanation and supporting documentation for these gross ACR values required by the December 19 Order.

206 Brattle Report at 2.

207 *See* Tariff, Attachment DD, section 6.8.

208 Brattle Report at 3.

209 Brattle Report at 2. Brattle explains that "all maintenance costs for systems directly related to electric production can be included in the operating costs maintenance adder for cost-based energy offers, and thus are excluded from the Avoidable Cost Rates." *Id.* at 2.

210 Brattle Report at 3 ("Our cost estimates are primarily based on our analysis of publicly-reported costs for plants with characteristics similar to the representative plants for each resource type, which we validated against confidential cost estimates within S&L's project database.").

Existing Resource Type	Default Gross ACR (2022/2023 ($/ICAP MW-day)
Nuclear - single	$697
Nuclear - dual	$445
Coal	$80
Combined Cycle	$56
Combustion Turbine	$50
Fixed Solar PV	$40
Wind Onshore	$83
Generation-backed Demand Response	$3
Load-backed Demand Response	$0
Energy Efficiency	$0

Generation-backed Existing Demand Resources may have going-forward costs associated with the operation and maintenance of the generating unit allowing the resource to participate in the capacity market. Brattle found that the "primary annual cost [for such units] is an annual maintenance contract to ensure the facility remains operational in case it is called upon."[211] Brattle "estimate[d] that their annual maintenance contracts cost about $1/kW, which translates to $3/MW-day."[212]

By contrast, for load-backed Existing Demand Resources and existing Energy Efficiency Resources, Mr. Keech explains that "PJM was unable to determine any material avoidable costs associated with these resource types,"[213] nor is PJM "aware of any material avoidable cost to carry forward the load reduction capability on an Existing Demand Resource or an existing Energy Efficiency Resource for electrical equipment

[211] Brattle Report at 24.

[212] Brattle Report at 24.

[213] Keech Aff. ¶ 35.

once an initial investment has been made."[214] Indeed, costs for such load-backed resources are upfront costs, i.e., installation of metering and software installations, that are applicable only to Planned Demand Resources. Accordingly, the default MOPR Floor Offer Price for load-backed Existing Demand Resources and existing Energy Efficiency Resources should be zero.[215]

As with the gross CONE values for New Entry Capacity Resources, PJM will review and re-evaluate these default gross ACR values as part of the quadrennial review of the VRR Curve and CONE values.[216]

As directed by the December 19 Order,[217] PJM determined default net E&AS revenues for each resource type on a Zonal basis and will net those values against the gross ACRs to determine the default MOPR Floor Offer Prices for Cleared Capacity Resources with State Subsidy.[218] While the December 19 Order directed "PJM to develop default average energy and ancillary services revenue offset values for each resource type by zone,"[219] it is somewhat unclear whether this directive is aimed at the development of default MOPR Floor Offer Prices for both new entry resources and existing resources. Nevertheless, pursuant to the December 19 Order, this filing will contain default net ACRs for each Zone and resource type.

Use of default zonal revenue values for new entry resources is logical, given that they have no performance history to rely on in determining market revenues. However,

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214 Keech Aff. ¶ 35.

215 Proposed Tariff, Attachment DD, section 5.14(h)(2)(B).

216 Proposed Tariff, Attachment DD, section 5.14(h)(2)(B).

217 December 19 Order at P 154.

218 Proposed Tariff, Attachment DD, section 5.14(h)(2)(B).

219 December 19 Order at P 154.

the use of default zonal revenues for existing resource may be less accurate, as the resource's history allows for a more accurate representation of its expected revenue offset. The context of the discussion supports the notion that this directive is for new resources only, as the December 19 Order is responding to PJM's October 2018 proposal to use the "lowest zonal value estimated for each resource type over the past three years" when determining the new entry floor prices.[220] The Market Monitor has sought clarification on the issue,[221] and PJM supports that request. Accordingly, in the event the Commission clarifies that the net E&AS revenue offset for determining floor prices for existing resources should be resource-specific rather than default zonal values, PJM will implement that directive.

Consistent with the underlying rationale for default CONE values, PJM does not propose default ACR values for hydroelectric resources and for resources whose primary purpose is not generating energy. A generic, default going-forward cost estimate for hydro resources would not be representative, because such resources are inherently site-specific, with unique landscape characteristics informing the size and capability or each resource. Accordingly, a resource-specific review is most appropriate for determining a MOPR Floor Offer Price for such resources. As for resources whose primary purpose is not generating energy, PJM lacks the necessary experience and data with these types of resources, but PJM may be able to provide a default value in the future through a separate FPA section 205 filing as it gains more experience. In the meantime, these resources must utilize the resource-specific process to obtain a MOPR Floor Offer Price. Hydro

[220] December 19 Order at P 154.

[221] Market Monitor Clarification Request at 3.

and non-primary purpose Capacity Resources for which Capacity Market Sellers fail to seek a resource-specific value will not be allowed to participate in RPM Auctions.[222]

J. Through the Resource-Specific Exception Process, Resources Subject to the MOPR May Be Offered at Prices Based on Their Actual Costs.

1. Commission Directive

The December 19 Order directed PJM to "maintain the Unit-Specific Exemption, expanded to cover existing and new State-Subsidized Resources of all resource types" to operate as an "alternative to the default offer price floor."[223] The Commission directed that resulting resource-specific floor offer price "will be based on the resource's expected costs and revenues,"[224] and the process should "largely track the Unit-Specific Exemption methodology set forth in PJM's currently-effective Tariff."[225] The Commission also found that PJM's standardization of certain financial modeling assumptions for the review process "appear to present a reasonable objective basis for the analysis."[226] Finally, the Commission required PJM to "provide more explicit information about the standards that will apply when conducting this review as a safeguard against arbitrary ad hoc determinations that market participants and the Commission may be unable to reliably predict or reconstruct."[227]

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222 Proposed Tariff, Attachment DD, section 5.14(h)(2)(B) ("Cleared Capacity Resources with State Subsidy for which there is no default MOPR Floor Offer Price provided in accordance with this section must seek a resource-specific value determined in accordance with the resource-specific MOPR Floor Offer Price process below to participate in an RPM Auction. Failure to obtain a resource-specific MOPR Floor Offer Price will result in the Office of the Interconnection rejecting any Sell Offer based on such resource.").

223 December 19 Order at P 214.

224 December 19 Order at P 214.

225 December 19 Order at P 214.

226 December 19 Order at P 16 n.36.

227 December 19 Order at P 216.

2. PJM Compliance Language

As directed by the December 19 Order, PJM is generally keeping in place the existing unit-specific exception process, and in fact, is able to maintain much of the existing Tariff language, with the revisions generally reflecting the expanded scope. However, in recognition of expanding the scope of the MOPR to apply to all types of resources and not just generation units, PJM is renaming it as the "resource-specific exception."[228] Thus, consistent with the current rules, any resource subject to the MOPR can demonstrate that its actual costs are lower than the applicable default MOPR Floor Offer Price, and if so, such resource is permitted to offer at that lower price. However, because the resource-specific price may turn out to be different from the default price, PJM is proposing to allow the Capacity Market Seller to choose to offer at either the default or resource-specific price level, regardless of the applicable offer cap.[229] This approach is reasonable, particularly at this early stage of information gathering so as not to work as a disincentive for Capacity Market Sellers willing to open their books with resource-specific information. In PJM's view, the market is better served with a process that allows for PJM and the Market Monitor to gain experience with and compile resource-specific information rather than creating a disincentive for entities seeking to invoke this approach. As the default values would have been determined by the Commission to be just and reasonable, this approach also ensures just and reasonable pricing outcomes for consumers.

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[228] Proposed Tariff, Attachment DD, section 5.14(h)(3).

[229] Proposed Tariff, Attachment DD, section 5.14(h)(3)(F) ("[T]he Capacity Market Seller may consider the applicable default MOPR Floor Offer Price and may select such default value if it is lower than the resource-specific determination, regardless of the offer cap applicable to such Capacity Resource.").

a. Resource-specific evaluations for New Entry Capacity Resources

The types of costs that will be considered in a resource-specific review will depend on whether the resource is New Entry Capacity Resource or a Cleared Capacity Resource with State Subsidy. For a New Entry Capacity Resource, the Capacity Market Seller must submit to PJM and the Market Monitor "documentation to support the fixed development, construction, operation, and maintenance costs of the Capacity Resource, as well as estimates of offsetting net revenues."[230] Further, PJM is generally keeping the standardized 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.[231]

PJM is clarifying the provisions to explicitly afford Capacity Market Sellers the ability to submit a resource-specific justification of an asset life other than the current default 20-year assumption. With the expansion of MOPR to apply to all other resource types, 20 years may not, in all instances, be appropriate as different resource types have different inherent characteristics that may allow them to remain economic for a longer period of time. In addition, PJM is clarifying the types of evidence that may be used to justify such an alternate asset life. Further documenting this existing flexibility, when justified by supporting evidence, provides for a reasonable level of flexibility given the diverse demographic of technologies the MOPR now applies to. Such documentation

230 Proposed Tariff, Attachment DD, section 5.14(h)(3)(B).

231 Proposed Tariff, Attachment DD, section 5.14(h)(3)(B).

may be provided to the Market Monitor (and ultimately PJM if there is disagreement between the unit owner and the Market Monitor) to demonstrate that 20 years may not be an appropriate asset life for that resource. PJM is proposing to cap the permissible term at 35 years, which is the general asset life assumption used in the ACR determination for the "Avoidable Project Investment Recovery Rate."[232] Further, in the December 19 Order, the Commission found projecting economic life for any period longer may be speculative.[233] An asset life of other than 20 years would not be allowed without sufficient justification; rather, a Capacity Market Seller must be able to substantiate that its financial accounting or project financing relies on an asset life that is different from 20 years.[234]

The above assumptions would apply to all resource types except load-backed and generation-backed Demand Resources and Energy Efficiency Resources. As the Commission correctly recognized, these resources operate differently and consider different cost (and savings) factors when deciding whether to participate in the capacity market.[235] Accordingly, as described below, the focus of each of the evaluations for these resource types is on the business calculus for participating in the capacity market, i.e., the costs incurred and demonstrable savings gained.

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232 Tariff, Attachment DD, section 6.8(a) (APIR (Avoidable Project Investment Recovery Rate)) (APIR uses a table for assigning a project investment cost recovery rate and assumes a 35-year life for each asset until the asset's actual life gets to 25 years, at which time the rate slows down as it anticipates the plant becoming uneconomic on a shorter horizon.).

233 *See, e.g.*, December 19 Order at P 153 n.301.

234 Proposed Tariff, Attachment DD, section 5.14(h)(3)(B). Capacity Market Sellers may submit other documentation regarding the resource's asset life, including "opinions of third-party experts regarding the reasonableness of the financing assumptions used for the project itself or in comparable projects to the extent the seller has not executed project financing for the resource (*e.g.*, independent project engineer opinion or manufacturer's performance guarantee)," and/or "evidence presented in federal filings, such as its FERC Form No. 1 or an SEC Form 10-K, to demonstrate an asset life other than 20 years of similar asset projects." *Id.*

235 *See* December 19 Order at PP 144-47.

To determine the resource-specific cost of new entry values for a load-backed Demand Resource, PJM will look at the "program costs required for the resource to meet the capacity obligations."[236] The Capacity Market Seller would need to substantiate such costs with documentation on topics "including all fixed operating and maintenance cost and weighted average cost of capital based on the actual cost of capital for the entity proposing to develop the Demand Resource."[237]

The resource-specific evaluation for Energy Efficiency Resources would be based documentation from the Capacity Market Seller regarding "the nominal-levelized annual cost to implement the [] program or to install the [] measure reflective of the useful life of the implemented [] equipment."[238] The evaluation would also consider "the offsetting savings associated with avoided wholesale energy costs and other claimed savings provided by implementing the [] program or installing the [] measure."[239]

Similarly, the generation-backed Demand Resource resource-specific determination "shall only consider the resource's costs related to participation in the Reliability Pricing Model and meeting a capacity commitment."[240] Because such resources are unit-specific, PJM is requiring the Capacity Market Seller to provide "supporting documentation (at the end-use customer level)" of the capacity market participation costs, and to attest that any generation unit-related costs not included are "not related to participation as a Demand Resource, such as the costs associated with installation and operation of the generation unit, and will be accrued and paid regardless

[236] Proposed, Tariff, Attachment DD, section 5.14(h)(3)(B).

[237] Proposed, Tariff, Attachment DD, section 5.14(h)(3)(B).

[238] Proposed, Tariff, Attachment DD, section 5.14(h)(3)(B).

[239] Proposed, Tariff, Attachment DD, section 5.14(h)(3)(B).

[240] Proposed, Tariff, Attachment DD, section 5.14(h)(3)(B).

of participation in the Reliability Pricing Model."[241] This parsing of costs recognizes the dual purpose the generation units that support such Demand Resources; indeed, such units are generally needed primarily for purposes other than participating in RPM, such as for resilience or regulatory requirements for hospitals. However, if the Capacity Market Seller chooses to include "all costs associated with the generation unit," only then will the evaluation consider "demand charge management benefits at the retail level (as supported by documentation at the end-use customer level)" as an additional offset to such costs.[242]

b. Resource-specific evaluations for Cleared Capacity Resources with State Subsidies

For Cleared Capacity Resources with State Subsidy, if a Capacity Market Seller believes that the default floor price overstates the actual costs of its resource, the Capacity Market Seller may request a resource-specific ACR determination.[243] The resource-specific determination would generally rely on the same going-forward cost data used to determine ACR offer caps under Tariff, Attachment DD, section 6.8, except that the determination would be precluded from using the 10% gross up for uncertainty which is used in setting the resource-specific offer cap.[244] Thus, for the cost portion of the analysis, Capacity Market Sellers would only need to submit such data on the avoidable

241 Proposed, Tariff, Attachment DD, section 5.14(h)(3)(B).

242 Proposed, Tariff, Attachment DD, section 5.14(h)(3)(B). PJM is proposing to allow Capacity Market Sellers to provide supporting documentation (at the end-use customer level) that includes "historic end-use customer bills and associated analysis that identifies the annual retail avoided cost from the operation of such generation unit." Proposed, Tariff, Attachment DD, section 5.14(h)(3)(B).

243 *See* proposed, Tariff, Attachment DD, section 5.14(h)(2)(B).

244 In section 6.8, the 10% gross up is part of the "Adjustment Factor," which also calls for adjusting the costs by the 10-year average Handy-Whitman Index. PJM proposes to apply this index when determining a resource's going forward cost for RPM Auctions, because the costs need to be adjusted upward to account for inflation between the auction and the Delivery Year.

cost components laid out in section 6.8. However, a resource's expected net E&AS revenues must be subtracted from its costs to determine how much revenue the resource needs from the capacity market. PJM proposes to apply the approach and type of data used to determine expected revenues for new resources. That is, Capacity Market Sellers may use either historical or forward looking energy revenues, just like PJM has long allowed for determining resource-specific values for new entry resources, and Capacity Market Sellers may also provide the same kind and types of projected revenue data.

While the resource-specific MOPR Floor Offer Price for Cleared Capacity Resources with State Subsidy and the Market Seller Offer Cap both rely on the similar sets of data to compute the ACR, the MOPR Floor Offer Price can exceed the resource-specific offer cap.[245] This could occur because, for example, the Capacity Market Seller used a forward-looking projection of revenues in the determination of the resource-specific MOPR Floor Offer Price, while the resource-specific offer cap determination only uses historical revenues. Because an offer at the applicable MOPR Floor Offer Price (whether resource-specific or default) is a valid, competitive offer representative of the resource's costs, such an offer should not "in and of itself, be deemed an exercise of market power in the RPM market."[246] Accordingly, in the event PJM must mitigate a Sell Offer down to the applicable Market Seller Offer Cap, PJM should only mitigate it down to "the higher of the applicable Market Seller Offer Cap or the applicable MOPR Floor Offer Price."[247]

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245 The same is true with respect to the default MOPR Floor Offer Prices and the default Market Seller Offer Cap, which is determined in accordance with Tariff, Attachment DD, section 6.4.

246 Proposed Tariff, Attachment DD, section 6.4(a).

247 Proposed Tariff, Attachment DD, section 6.5(a)(i).

In addition and consistent with the determination of the default values, PJM will require Capacity Market Sellers to include in the estimates of expected market revenues various costs including, as applicable, Maintenance Adders, Fuel Costs, and Operating Costs.[248]

Finally, to "safeguard against arbitrary ad hoc determinations,"[249] PJM is proposing one small clarifying modification to the process language. Specifically, PJM is proposing that the resource-specific review process be "open and transparent" as between the Market Monitor, the Capacity Market Seller, and PJM.[250] This change should not affect the data required from the Capacity Market Seller or actually change any aspect of processing such requests. Rather, it merely ensures that PJM and the Market Monitor are kept apprised of each other's review.[251] This will maximize the sharing of information, analysis, and dialogue between PJM, the Market Monitor, and the Capacity Market Seller.

K. PJM is Providing Special Procedures in Cases of Fraud or Material Misrepresentations.

As a necessary corollary to the above Tariff changes and to ensure Capacity Market Sellers provide complete and accurate information regarding the status of their resource with regards to State Subsidies, its eligibility for one of the exemptions to the MOPR described in this compliance filing, or information in the resource-specific review process, PJM is including safeguard provisions to address the consequences if PJM

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248 Proposed Tariff, Attachment DD, section 5.14(h)(3)(C).

249 December 19 Order at P 216.

250 *See* proposed Tariff, Attachment DD, section 5.14(h)(3)(F).

251 As PJM explained in its request for clarification, PJM is maintaining the current roles for PJM and the Market Monitor when reviewing resource-specific exceptions. Specifically, PJM will make the final determination of a resource-specific price with advice and input from the Market Monitor. *See* PJM Rehearing Request at 24-25.

reasonably believes that a previous determination of whether a resource is a Capacity Resource with State Subsidy was based on fraudulent or material misrepresentations or omissions and, absent such misrepresentations or omissions, the resource's Capacity Resource with State Subsidy status would be different.[252] These provisions are closely modeled on the fraud and misrepresentation provisions the Commission previously accepted in Docket No. ER13-535 with regard to Capacity Market Sellers seeking a categorical exemption from the MOPR.[253]

Under these provisions, if PJM or the Market Monitor suspect misrepresentation or omission in the Capacity Market Seller's certification, either may request additional information "to evaluate whether such Capacity Resource is a Capacity Resource with State Subsidy," and the Capacity Market Seller must provide such information within five business days.[254] If PJM suspects the misrepresentation or omission sufficiently in advance of the start of the auction, it can alter the Capacity Resource with State Subsidy status for that auction (e.g., deem the resource a Capacity Resource with State Subsidy), but only upon written notification to the Capacity Market Seller no later than 65 days before the start of the auction.[255] If PJM provides written notice of such determination no later than 65 days before the relevant RPM Auction, then the resource will be deemed a Capacity Resource with State Subsidy and subject to the MOPR. Capacity Market Sellers that are dissatisfied with PJM's determination regarding its status may challenge it

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252 *See* proposed Tariff, Attachment DD, section 5.14(h)(9).

253 *See PJM Interconnection, L.L.C.*, 143 FERC ¶ 61,090, at P 115 (2013). PJM also proposed similar provisions as part of its original MOPR-Ex proposal in ER18-1314. Capacity Repricing or in the Alternative MOPR-Ex Proposal: Tariff Revisions to Address Impacts of State Public Policies on the PJM Capacity Market of PJM Interconnection, L.L.C., Docket No. ER18-1314-000, at Attachment C (Option B: Tariff, Attachment DD, section 5.14(h)(12)) (Apr. 9, 2018).

254 Proposed Tariff, Attachment DD, section 5.14(h)(9)(A).

255 Proposed Tariff, Attachment DD, section 5.14(h)(9)(A).

at the Commission. However, if PJM determines, contrary to the Capacity Market Seller's certification, that a resource is actually a Capacity Resource with State Subsidy, such Capacity Resource shall be subject to the MOPR, unless and until ordered to do otherwise by the Commission.[256]

The provisions expressly provide Capacity Market Sellers with the opportunity to challenge PJM's determination before the Commission. If PJM fails to provide written notice at least 65 days before the start of the relevant RPM Auction, then PJM may file with the Commission the suspect certification that contains any fraudulent or material misrepresentation or omission.[257] PJM will proceed to run the auction consistent with its determination, but will implement any Commission directive with respect to such suspect certification.

In any event, before PJM exercises its authority to timely alter a resource's status or before PJM submits a filing to the Commission concerning such remedy, PJM, with advice and input of the Market Monitor, will notify the Capacity Market Seller to provide the Capacity Market Seller an opportunity to explain the alleged misrepresentation or omission.[258] Thus, the Capacity Market Seller is provided the opportunity to submit a revised certification for that Capacity Resource for subsequent RPM auctions, including RPM Auctions held during the pendency of a Commission proceeding.[259] Finally, PJM will seek fast-track treatment for any such filing, and reveal neither the name nor any

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[256] Proposed Tariff, Attachment DD, section 5.14(h)(9)(A). Nothing in this proposed section affects the Market Monitor's existing authority under Tariff, Attachment M – Appendix.

[257] Proposed Tariff, Attachment DD, section 5.14(h)(9)(B).

[258] Proposed Tariff, Attachment DD, section 5.14(h)(9)(C).

[259] Proposed Tariff, Attachment DD, section 5.14(h)(9)(C).

identifying characteristics of the Capacity Market Seller or its resource, though the filing shall otherwise be public.[260]

IV. AUCTION IMPLEMENTATION SCHEDULE AND ASSOCIATED TARIFF WAIVER REQUEST

A. PJM Proposes a Slightly Compressed Schedule for the 2022/2023 Delivery Year BRA Tied to the Date of the Commission's Order Accepting the Compliance Filing.

The December 19 Order makes clear the Commission's expectation that PJM's next BRA "be conducted under the new rules to provide the necessary and appropriate price signals to capacity resources."[261] In that vein, the Commission directed PJM, in this compliance filing, "to provide an updated timetable for when it proposes to conduct the 2019 BRA, as well as the 2020 BRA, as necessary."[262]

PJM was previously scheduled to conduct the BRA to obtain capacity commitments for the 2022/2023 Delivery Year, per the then-effective Tariff, in May 2019. Given the pendency of this proceeding, the Commission in August 2018 granted PJM's request for waiver of the Tariff requirement to conduct that auction in May 2019, as well as waiver of certain related Tariff deadlines for PJM, the Market Monitor, and Capacity Market Sellers to complete various pre-auction tasks, such that PJM would conduct the BRA in August 2019.[263] When PJM later sought clarification that, because this proceeding remained pending, PJM should proceed with the August 2019 auction schedule per the Waiver Order, the Commission instructed PJM not to proceed with the auction, because the effective offer pricing rules had been found unjust and unreasonable,

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[260] Proposed Tariff, Attachment DD, section 5.14(h)(9)(C).

[261] December 19 Order at P 219.

[262] December 19 Order at P 219.

[263] *PJM Interconnection, L.L.C.*, 164 FERC ¶ 61,153 (2018) ("Waiver Order").

and there was no just and reasonable replacement rate yet determined.[264] In doing so, however, the Commission expressly recognized "the magnitude of the tariff process at issue—the BRA, a major feature of the PJM market—and the corresponding interest of market participants who make resource investment and retirement decisions based on price signals."[265] The Commission further recognized "the importance of sending price signals sufficiently in advance of delivery to allow for resource investment decisions."[266] The Commission found, however, that "on balance, delaying the auction until the Commission establishes a replacement rate will provide greater certainty to the market."[267]

The December 19 Order outlines the key elements of the just and reasonable replacement rate. Given the complexity of PJM's capacity auction rules however—PJM's October 2018 pro forma Tariff revisions on a proposed replacement rate, for example, ran to over 30 pages—and the many details of the replacement rate of necessity left to be addressed by this compliance filing, resuming the capacity auctions again requires a balance between "the importance of sending price signals sufficiently in advance of delivery to allow for resource investment decisions;" and clearly "establish[ing] a replacement rate [to] provide greater certainty to the market."[268]

Accordingly, PJM urges that it not be required to conduct the next BRA until the Commission has acted on this compliance filing and approved the operative Tariff language that will govern that auction. Capacity Market Sellers should know before they

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264 *PJM Interconnection, L.L.C.*, 168 FERC ¶ 61,051 (2019) ("July Auction Order").

265 July Auction Order at P 14.

266 July Auction Order at P 14.

267 July Auction Order at P 14.

268 July Auction Order at P 14.

make concrete auction preparations, for example, the specific definition of a State Subsidy, the details of available exemptions, the Net CONE and ACR screening values for the various resource categories, and the parameters of an acceptable unit-specific exception showing—just to name a few. Therefore, PJM proposes that the date for the next BRA Auction be tied to the date of the Commission's order on this compliance filing.

Specifically, PJM proposes to complete all pre-auction activities and open the BRA for the 2022/2023 Delivery Year within six and a half months after the date of the Commission's acceptance of PJM's compliance filing. In the interest "of sending price signals sufficiently in advance of delivery," the six and a half month schedule is compressed from the Tariff-prescribed schedule that has governed prior BRAs. Under the current Tariff, the pre-auction schedule begins eight and a half months before the BRA, when Capacity Market Sellers must provide their preliminary must-offer exception requests for anticipated deactivations. Those exception requests must be confirmed five and a half months before the BRA, and (as a critical-path item in the proposed replacement rate) Capacity Market Sellers will be required to certify whether or not their Capacity Resources are eligible to receive State Subsidies no later than four months before the auction.[269] The coordinated and inter-related pre-auction deadlines for PJM, the Market Monitor, Capacity Market Sellers, and FRR Entities proceed quickly from that point—and will now include multiple additional deadlines to implement the replacement rate.

[269] As explained above, however, the certification deadline applicable to Demand Resources and Energy Efficiency Resources is 30 days before the RPM Auction.

The proposed schedule has two components: (1) the first two weeks after the order on this compliance filing is an initial adjustment and preparation period for PJM and stakeholders, with no pre-auction deadlines; and (2) the next six months is a condensed version of the existing pre-auction schedule, as shown in the graphic below. PJM notes that the first proposed deadline for Capacity Market Sellers is not until 18 days into that pre-auction process, i.e., the final request for a must-offer exception must be submitted no later than 162 days before the start of the BRA.[270] As part of this schedule compression, PJM is eliminating the requirement for a preliminary notification of a must-offer exception request—which was non-binding in any event—for the impacted Delivery Years.

B. PJM Proposes a Balanced (and Contingent) Scheduling Accommodation for the 2022/2023 Delivery Year BRA to Address the Possibility of Near-Term Enactment of New State Laws on FRR Eligibility.

Under the above approach, if the Commission were to issue its order on the compliance filing by mid-May, PJM would conduct the delayed 2019 BRA no later than December of this year. PJM is aware, however, that the OPSI has proposed that PJM defer the 2019 BRA to May 2021.[271] PJM understands this request to stem from the December 19 Order's impact on state resource policies, and the resulting possibility of state legislation in the next few months that responds to the December 19 Order in a manner that has a material impact on multiple market participants' preparations for and participation in the auction. PJM is sensitive to this concern, but also recognizes the

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270 *See* Attachment A to this filing.

271 *See* Letter from Dr. Talina R. Mathews, President, Organization of PJM States, Inc. (OPSI), to Ake Almgren, PH.D., Chairman, The PJM Board of Managers, PJM Interconnection, L.L.C. (Feb.13, 2020), https://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/20200219-opsi-letter-re-scheduling-next-base-case-residual-auction.ashx?la=en.

importance of resuming the BRA schedule as soon as possible. To address this concern and balance the interest in accommodating the request made by OPSI with the need for some market certainty as market participants make critical resource financing decisions, PJM proposes that, in the event that legislation directly applicable to new elections of the FRR alternative is enacted before June 1, 2020,[272] and upon request of a state public utility commission acting in its official capacity, PJM would have the limited ability to extend the schedule for the affected BRA to no later than March 31, 2021, for completion of the BRA. That limited, conditional extension would allow PJM to conduct an orderly auction schedule that takes such a material change into account, with the least amount of delay in the overall schedule.

PJM proposes to post the specific schedule for the 2022/2023 BRA and subsequent RPM Auctions consistent with the above description by the later of June 15, 2020, or 14 days after a Commission order accepting the compliance filing.[273] In this way, PJM's announcement of the specific auction schedule dates will take into account whether state legislation triggering the three-month extension has been enacted. Once the auction schedule is posted, it will be final and not allowed to be further modified unless otherwise directed by the Commission.

C. PJM Proposes an Orderly and Deliberate Serial Implementation of BRAs for the 2023/2024 Through 2025/2026 Delivery Years to Return RPM to Its Intended 36-Month Forward Schedule.

As shown in the figure below, PJM proposes a four and a half month pre-auction schedule for the BRAs for each of the three succeeding Delivery Years, with that

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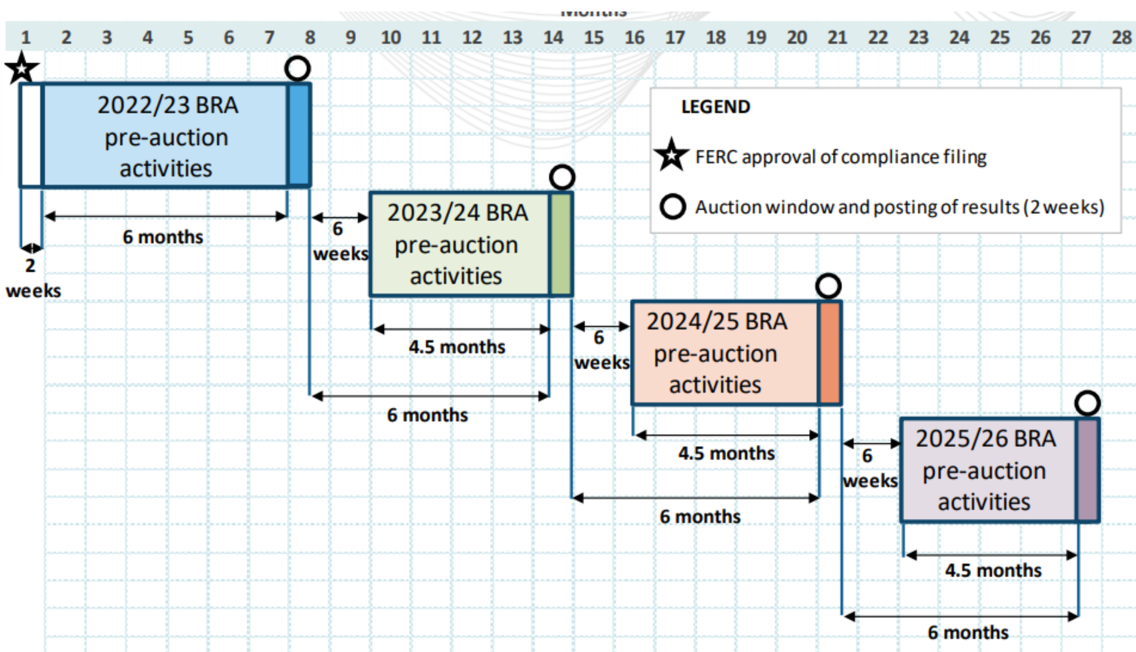
272 By "enact," PJM means that any such legislation is not only passed by the legislature, but also signed by the authorized state executive, no later than June 1, 2020.

273 As noted above, the first deadline affecting market participants would not arise until 18 days after the start of the formal pre-auction process.

schedule in each case beginning six weeks after the posting of the prior BRA's results. PJM proposes adjustments to the next three BRAs because the existing delay is already such that the prompt and orderly consecutive conduct of the BRAs for the 2022/2023 and 2023/2024 Delivery Years will impinge on the schedules for the BRAs for the two subsequent Delivery Years.

Similar to the BRA for the 2022/2023 Delivery Year, PJM will allow a period of time, six weeks in this case, before the formal pre-auction process begins. This deliberate and timely schedule: (1) allows a reasonable initial period for market participants to assess the results of the prior BRA; (2) allows sufficient time (albeit slightly compressed from the standard schedule) to conduct pre-auction activities; and (3) puts the PJM Region on track to return to the designed three-year forward BRA schedule in the least time consistent with an orderly process.



The proposed timeline also upholds the importance of, and the market's expectation of, consecutive BRA schedules for consecutive Delivery Years. Market participants reasonably should be afforded the benefit of knowing results from the prior Delivery Year's BRA in order to plan their competitive offers and strategies for the next BRA. For example, Capacity Market Sellers should not have to make a deactivation decision for a Delivery Year without knowing the cleared quantities and clearing prices for the preceding Delivery Year.

PJM proposes to post for the 2023/2024, 2024/2025, 2025/2026 Delivery Years the specific BRA schedules and all intermediate deadlines, at the same time PJM posts the BRA schedule for the 2022/2023 Delivery Year.

D. PJM Proposes to Adjust the Incremental Auction Schedule to Reflect the Shortened Time Between the BRAs and Their Associated Delivery Years.

The delay in the BRAs for the affected Delivery Years also requires changes to the IA schedule for those Delivery Years, which assume three years between the closing of a BRA and the start of the associated Delivery Year. The Tariff accordingly requires the First IA to be held in the month of September that is 20 months before the start of the Delivery Year, the Second IA to be held in the month of July that is 11 months before the start of the Delivery Year, and the Third IA to be held in the month of February that is three months before the start of the Delivery Year.[274]

Because the BRAs for the first three affected Delivery Years will be held substantially less than 36 months before the start of their respective Delivery Years, PJM proposes to cancel some of those IAs. PJM's proposed cancellations are guided by the following considerations:

- schedule compression placing an IA in close proximity to its BRA;

274 *See* Tariff, Definitions E-F (definition of First Incremental Auction), Definitions R-S (definition of Second Incremental Auction), Definitions T-U-V (definition of Third Incremental Auction).

- schedule compression resulting in IAs being conducted without a material change in the planning parameters or auction inputs;
- the IA's normally scheduled date has already passed;
- the IA would fall within 10 months of the associated BRA; and
- PJM should always conduct a Third IA for each Delivery Year, to take account of the final load forecast and Equivalent Demand Forced Outage Rates for that Delivery Year.

Consistent with these principles, PJM proposes to cancel any IAs that the current Tariff would otherwise require PJM to conduct at a time that is within 10 months after the delayed date on which PJM actually concludes the BRA for that same Delivery Year. The specific IAs that will be canceled depend on the timing of the Commission's order on this compliance filing, and on whether the conditional three-month added time is invoked for the BRA for the 2022/2023 Delivery Year. However, in no event will the Third IA be canceled or postponed for any Delivery Year.

E. PJM Formally Requests Waiver of Its Tariff as Necessary to Permit Implementation of PJM's Response to the December 19 Order's Compliance Directive for an Updated RPM Auction Timetable.

To permit the proposed BRA and IA schedules, PJM requests waiver of the PJM Tariff provisions—listed in Attachment A to this filing—on BRA and IA timing and BRA pre-auction process deadlines. PJM reads the Commission's order denying PJM's request to proceed with the 2022/2023 BRA in August 2019, as effectively extending the Tariff waivers granted in the Waiver Order that allowed PJM to defer that BRA from its Tariff-prescribed May 2019 timing.[275] PJM thus views the Commission's forthcoming

[275] In the Waiver Order, the Commission granted waiver of: "(1) Attachment DD, section 5.4(a), requiring that the BRA be conducted in May three years prior to the relevant delivery year; (2) Attachment DD, sections 5.10(a)(vi)(B) and 5.10(d), requiring PJM to post by February 1 before the BRA the [VRR] curves to be used in the BRA and the Preliminary PJM Region Peak Load Forecast for the delivery year; and (3) Attachment DD, section 6.6(g), requiring any Capacity Market Seller seeking an exception to the BRA must-offer requirement on the basis of the deactivation of its resource to submit a preliminary written request by the September 1

compliance order in this docket as completing the Commission's action on that previously filed waiver request. PJM now requests that the Commission expand that prior waiver to any other Tariff-required pre-auction deadline that has been disrupted, including the changes in the IAs. Attachment A to this filing details each such deadline, the governing Tariff provision for each such deadline, and PJM's proposed alternative timing for each such deadline.[276]

Given the evident impossibility of conducting the 2023/2024 BRA in May 2020, as required by the current Tariff, and the cascading impacts on the BRAs for the 2024/2025 and the 2025/2026 Delivery Years from the schedule delays for the prior Delivery Years' BRAs, PJM also requests that the Commission grant the same waiver the Commission granted in the Waiver Order to the 2022/2023 BRA and for the BRAs and IAs in the three subsequent Delivery Years (and their relevant pre-auction deadlines). Attachment A shows the deadlines, the governing Tariff provisions, and PJM's proposed alternative deadline for these three Delivery Years as well.

In the Waiver Order, the Commission found such waivers needed to accommodate delay of the BRA auction schedule from the Tariff-prescribed deadlines was consistent with the Commission's waiver policy because "(1) the applicant acted in

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preceding the BRA, and provide confirmation by December 1." Waiver Order at P 4; *see also id*. at P 12.

[276] PJM also requests waiver of three requirements in the RAA that PJM calculate certain parameters used in determining capacity obligations based on three or four years before a given BRA. Given the delayed and compressed schedule for holding the next four BRAs, PJM requests waiver of these "hard-coded" requirements to use data from certain calendar years, and instead seeks relief to use "the most recent available" data. Specifically, PJM seeks waiver of the requirement in RAA, Schedule 8, section (B) and RAA, Schedule 8.1(D)(3) to allow PJM to use most recent available the "Zonal Weather-Normalized Summer Peak Load" instead of the one "for the summer season concluding four years prior to the commencement of such Delivery Year." In addition, PJM seeks waiver of the requirement in RAA, Schedule 8.1(D)(4) that all demand response and similar load management programs included in an FRR Capacity Plan "be submitted three years in advance" of the Delivery Year; rather, the FRR Entity should be allowed to submit them before the BRA for such Delivery Year.

good faith; (2) the waiver is of limited scope; (3) the waiver addresses a concrete problem; and (4) the waiver does not have undesirable consequences, such as harming third parties."[277]

The same is true here. The BRAs and IAs for the four impacted Delivery Years cannot be held on their Tariff-prescribed timing, because the rules to govern those auctions are not yet fully resolved or detailed, the BRA for the prior year has not yet been held, and Market Participants, PJM, the Market Monitor, and other stakeholders have insufficient time to prepare for the orderly consecutive conduct of those auctions. Just as found in the Waiver Order under very similar conditions, PJM has acted in good faith, the problem is concrete, the waiver is of limited scope, and the waiver will not have undesirable consequences. The consequences of conducting auctions—committing resources to the region's capacity needs and determining clearing prices and results—are the same consequences of conducting all past RPM Auctions. The pre-auction schedule for each BRA is compressed, but not in a major way—parties will still have sufficient time to make their pre-auction arrangements, as can be seen from the intervals set forth on Attachment A. The largest schedule change is that there will be less time between the posting of one BRA's results and the start of the pre-auction process for the next BRA, but six weeks for that interval still allows a reasonable amount of time for parties to assess auction results, and parties also will have six months after one BRA clearing before they submit offers in the next BRA. The main difference now is that the longer delay (compared to PJM's earlier waiver request) in establishing the replacement rules for the RPM Auctions now impacts the schedule for more RPM Auctions. The problem

[277] Waiver Order at P 12 (citing *Midcontinent Indep. Sys. Operator, Inc.*, 154 FERC ¶ 61,059, at P 14 (2016); *Calpine Energy Servs., L.P.*, 154 FERC ¶ 61,082, at P 12 (2016); *N.Y. Power Auth.*, 152 FERC ¶ 61,058, at P 22 (2015)).

remains concrete, i.e., effecting an orderly resumption of the BRAs in light of the delay; and the scope is no greater than is needed to restore the BRAs to their intended three-year-advance design.

Granting of the waiver will not have undesirable consequences. The consequences of conducting auctions—committing resources to the region's capacity needs and determining clearing prices and results—are the same consequences of conducting all past RPM auctions. The pre-auction schedule for each BRA is compressed, but not in a major way—parties will still have sufficient time to make their pre-auction arrangements, as can be seen from the intervals set forth on Attachment A. The largest schedule change is that there will be less time between the posting of one BRA's results and the start of the pre-auction process for the next BRA. However, six weeks for that interval still allows a reasonable amount of time for parties to assess auction results, and parties also will have six months after one BRA clearing before they submit offers in the next BRA. In sum, the requested waiver will allow PJM to proceed on a compressed, deliberate path to resume the consecutive conduct of the BRAs—as required by the PJM Tariff—which has been disrupted by the pendency of this proceeding.

V. EFFECTIVE DATE

Because certain elements of the Commission's December 19 Order provided latitude in the details of the design, PJM will await a Commission order accepting these rules before implementing them. As noted above, PJM will announce the revised schedule for certain RPM Auctions shortly after receipt of the Commission's order accepting the compliance filing, providing notice of the date on which PJM intends to implement the modified MOPR rules.[278]

VI. DOCUMENTS ENCLOSED

PJM encloses the following:

1. This transmittal letter;
2. Attachment A: Schedule of BRA pre-auction deadlines and IA schedule;
3. Attachment B: Revised sections of the Tariff and RAA (redlined version);
4. Attachment C: Revised sections of the Tariff and RAA (clean version);
5. Attachment D: Brattle Affidavit, including the Brattle Report; and
6. Attachment E: Keech Affidavit, including an appended workbook.

278 As such, PJM has coded the tariff sections accompanying this filing with a December 31, 9998 effective date.

VII. COMMUNICATIONS

Correspondence and communications with respect to this filing should be sent to the following persons:

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VIII. SERVICE

PJM has served a copy of this filing on all PJM Members and on the affected state utility regulatory commissions in the PJM Region by posting this filing electronically. In accordance with the Commission's regulations,[279] PJM will post a copy of this filing to the FERC filings section of its internet site, located at the following link: http://www.pjm.com/documents/ferc-manuals/ferc-filings.aspx with a specific link to the newly-filed document, and will send an e-mail on the same date as this filing to all PJM Members and all state utility regulatory commissions in the PJM Region[280] alerting them that this filing has been made by PJM and is available by following such link. If the document is not immediately available by using the referenced link, the document will be

[279] *See* 18 C.F.R. §§ 35.2(e) and 385.2010(f)(3).

[280] PJM already maintains, updates, and regularly uses e-mail lists for all PJM Members and affected state commissions.

available through the referenced link within 24 hours of the filing.

Also, a copy of this filing will be available on the Commission's eLibrary website located at the following link: http:/www.ferc.gov/docs-filing/elibrary.aspx in accordance with the Commission's regulations and Order No. 714.[281]

IX. CONCLUSION

PJM respectfully requests that the Commission accept this compliance filing. As explained above, PJM proposes to post the specific schedule for the 2022/2023 BRA and subsequent RPM Auctions consistent with the above description by the later of June 15, 2020, or 14 days after the order accepting the compliance filing.

Respectfully submitted,

/s/ Ryan J. Collins

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March 18, 2020

[281] *Electronic Tariff Filings*, Order No. 714, 124 FERC ¶ 61,270 (2008), *final rule*, Order No. 714-A, 147 FERC ¶ 61,115 (2014).

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, D.C., this 18th day of March 2020.

/s/ Ryan J. Collins
Ryan J. Collins

Attachment A

Schedule of BRA pre-auction deadlines and IA schedule

"Adjusted Days Prior" refer to PJM's requested modified deadline for the corresponding activity prior to the relevant BRA. "Deadline" refers to the current Tariff imposed deadlines for the corresponding activity.

Base Residual Auctions			**2022/2023 Delivery Year**	**2023/2024, 2024/2025, and 2025/2026 Delivery Years**
Actor	**Pre-Auction Task or Activity**	**Deadline, with Tariff Source**	**Adjusted Days Prior**	**Adjusted Days Prior**
PJM	PJM solicits requests for Winter CIRs	Aug. 31 of each calendar year (OATT IV Preamble)	170	145
Seller	Seller Final Must-Offer exception request (Deactivation)	Dec. 1 prior to BRA (OATT DD 6.6)	162	135
PJM	PJM posts DR Zones of Concern	Dec. 1 prior to BRA (OATT DD-1)	162	135
Seller	Seller Preliminary Must-Offer exception request (Deactivation)	Sept. 1 prior to BRA (OATT DD 6.6)	waived	waived
Seller	Seller Peak-Shaving Adjustment Plans	10 business days prior to Sept. 30 for next LF (OATT DD-2)	135	135
Seller	Seller request for Winter CIRs	Oct. 31 prior to BRA (OATT IV Preamble)	135	135
Seller	Seller Actionable Subsidy specification	150 days prior to BRA (OATT DD 5.14)	150	135
PJM	Post Preliminary MOPR Screen Prices	150 days prior to auction (OATT DD 5.14)	150	150
FRR Entity	FRR first-time election	4 months prior to BRA (RAA Schedule 8.1.C)	121	121

Base Residual Auctions			**2022/2023 Delivery Year**	**2023/2024, 2024/2025, and 2025/2026 Delivery Years**
Actor	**Pre-Auction Task or Activity**	**Deadline, with Tariff Source**	**Adjusted Days Prior**	**Adjusted Days Prior**
Seller	Seller unit-specific MOPR request & Self-Supply Exemption	120 days prior to BRA (OATT DD 5.14)	120	120
Seller	Seller unit-specific request (Must-Offer, Offer Cap, EFORd)	120 days prior to auction (OATT 6.6)	120	120
Seller	Seller PRD Plan	Jan. 15 prior to BRA (RAA Schedule 6.1)	117	117
PJM	PJM posts Planning Parameters	Feb. 1 prior to BRA (M18; OATT DD 15)	100	100
Market Monitor	Market Monitor Determination (MOPR)	90 days prior to auction (OATT M – Appendix)	90	90
Market Monitor	Market Monitor Determination (Must-Offer, Offer Cap, EFORd)	90 days prior to auction (OATT M – Appendix)	90	90
Seller	Seller Notification to PJM (Must-Offer, Offer Cap, EFORd)	80 days prior to auction (OATT DD 5.14 & 6.6)	80	80
PJM	PJM Determination (MOPR & Self-Supply Exemption)	65 days prior to auction (OATT DD 5.14)	65	65
PJM	PJM Determination (Must-Offer, Offer Cap, EFORd)	65 days prior to auction (OATT DD 5.14 & 6.6)	65	65
Seller	Seller Notification of intent to exclude Must-Offer Exception MW	65 days prior to auction (OATT DD 6.6)	65	65
FRR	FRR termination of election	2 months prior to BRA (RAA Schedule	61	61

Base Residual Auctions			**2022/2023 Delivery Year**	**2023/2024, 2024/2025, and 2025/2026 Delivery Years**
Actor	**Pre-Auction Task or Activity**	**Deadline, with Tariff Source**	**Adjusted Days Prior**	**Adjusted Days Prior**
Entity		8.1.C)		
Seller	Seller Confirmation of MOPR price	60 days prior to auction (OATT DD 5.14)	60	60
FRR Entity	FRR DR Plan	15 business days prior to FRR Plan (OATT DD-1)	49	49
Seller	Seller needs ICTR/QTU certification of CETL increase	45 days prior to BRA (OATT DD 5.6.4)	45	45
Seller	Seller election of RCO and carved out MW	30 days prior to BRA (OATT DD 5.14)	30	30
Seller	Seller election to forgo Actionable Subsidy	30 days prior to auction (OATT DD 5.14)	30	30
FRR Entity	FRR Capacity Plan	1 month prior to BRA (RAA Schedule 8.1.C)	30	30
Seller	Seller Energy Efficiency Plan	30 days prior to auction (OATT DD-1)	30	30
Seller	Seller DR Plan	15 business days prior to auction (OATT DD-1)	21	21
PJM	PJM posts Aggregate MW of RCO units	20 days prior to BRA (OATT DD 5.11)	20	20

Incremental Auctions

Actor	Pre-Auction Task or Activity	Deadline, with Tariff Source	For Delivery Years 2022/2023 through 2025/2026
PJM	First Incremental Auction	20 months prior to the start of the Delivery Year to which it relates (OATT Definitions E-F)	Canceled if within 10 months of revised BRA update
PJM	Second Incremental Auction	10 months before the Delivery Year to which it relates (OATT Definitions R-S)	Canceled if within 10 months of revised BRA update

Attachment B

Revisions to the
PJM Open Access Transmission Tariff
and
PJM Reliability Assurance Agreement

(Marked / Redline Format)

Sections of the
PJM Open Access Transmission Tariff

(Marked / Redline Format)

Definitions – C-D

Canadian Guaranty:

"Canadian Guaranty" shall mean a Corporate Guaranty provided by an Affiliate of a Participant that is domiciled in Canada, and meets all of the provisions of Tariff, Attachment Q.

Cancellation Costs:

"Cancellation Costs" shall mean costs and liabilities incurred in connection with: (a) cancellation of supplier and contractor written orders and agreements entered into to design, construct and install Attachment Facilities, Direct Assignment Facilities and/or Customer-Funded Upgrades, and/or (b) completion of some or all of the required Attachment Facilities, Direct Assignment Facilities and/or Customer-Funded Upgrades, or specific unfinished portions and/or removal of any or all of such facilities which have been installed, to the extent required for the Transmission Provider and/or Transmission Owner(s) to perform their respective obligations under Tariff, Part IV and/or Tariff, Part VI.

Capacity:

"Capacity" shall mean the installed capacity requirement of the Reliability Assurance Agreement or similar such requirements as may be established.

Capacity Emergency Transfer Limit:

"Capacity Emergency Transfer Limit" or "CETL" shall have the meaning provided in the Reliability Assurance Agreement.

Capacity Emergency Transfer Objective:

"Capacity Emergency Transfer Objective" or "CETO" shall have the meaning provided in the Reliability Assurance Agreement.

Capacity Export Transmission Customer:

"Capacity Export Transmission Customer" shall mean a customer taking point to point transmission service under Tariff, Part II to export capacity from a generation resource located in the PJM Region that has qualified for an exception to the RPM must-offer requirement as described in Tariff, Attachment DD, section 6.6(g).

Capacity Import Limit:

"Capacity Import Limit" shall have the meaning provided in the Reliability Assurance Agreement.

Capacity Interconnection Rights:

"Capacity Interconnection Rights" shall mean the rights to input generation as a Generation Capacity Resource into the Transmission System at the Point of Interconnection where the generating facilities connect to the Transmission System.

Capacity Market Buyer:

"Capacity Market Buyer" shall mean a Member that submits bids to buy Capacity Resources in any Incremental Auction.

Capacity Market Seller:

"Capacity Market Seller" shall mean a Member that owns, or has the contractual authority to control the output or load reduction capability of, a Capacity Resource, that has not transferred such authority to another entity, and that offers such resource in the Base Residual Auction or an Incremental Auction.

Capacity Performance Resource:

"Capacity Performance Resource" shall mean a Capacity Resource as described in Tariff, Attachment DD, section 5.5A(a).

Capacity Performance Transition Incremental Auction:

"Capacity Performance Transition Incremental Auction" shall have the meaning specified in Tariff, Attachment DD, section 5.14D.

Capacity Resource:

"Capacity Resource" shall have the meaning provided in the Reliability Assurance Agreement.

Capacity Resource with State Subsidy:

"Capacity Resource with State Subsidy" shall mean (1) a Capacity Resource that is offered into an RPM Auction or otherwise assumes an RPM commitment for which the Capacity Market Seller receives or is entitled to receive one or more State Subsidies for the applicable Delivery Year; (2) a Capacity Resource that has not cleared an RPM Auction for the Delivery Year for which the Capacity Market Seller last received a State Subsidy (or any subsequent Delivery Year) shall still be considered a Capacity Resource with State Subsidy upon the expiration of such State Subsidy until the resource clears an RPM Auction; (3) a Capacity Resource that is the subject of a bilateral transaction (including but not limited to those reported pursuant to Tariff, Attachment DD, section 4.6) shall be deemed a Capacity Resource with State Subsidy to the extent an owner of the facility supporting the Capacity Resource is entitled to a State Subsidy associated with such facility even if the Capacity Market Seller is not entitled to a State Subsidy; and (4) any Jointly Owned Cross-Subsidized Capacity Resource.

Capacity Resource Clearing Price:

"Capacity Resource Clearing Price" shall mean the price calculated for a Capacity Resource that offered and cleared in a Base Residual Auction or Incremental Auction, in accordance with Tariff, Attachment DD, section 5.

Capacity Storage Resource:

"Capacity Storage Resource" shall mean any Energy Storage Resource that participates in the Reliability Pricing Model or is otherwise treated as capacity in PJM's markets such as through a Fixed Resource Requirement Capacity Plan.

Capacity Transfer Right:

"Capacity Transfer Right" shall mean a right, allocated to LSEs serving load in a Locational Deliverability Area, to receive payments, based on the transmission import capability into such Locational Deliverability Area, that offset, in whole or in part, the charges attributable to the Locational Price Adder, if any, included in the Zonal Capacity Price calculated for a Locational Delivery Area.

Capacity Transmission Injection Rights:

"Capacity Transmission Injection Rights" shall mean the rights to schedule energy and capacity deliveries at a Point of Interconnection of a Merchant Transmission Facility with the Transmission System. Capacity Transmission Injection Rights may be awarded only to a Merchant D.C. Transmission Facility and/or Controllable A.C. Merchant Transmission Facilities that connects the Transmission System to another control area. Deliveries scheduled using Capacity Transmission Injection Rights have rights similar to those under Firm Point-to-Point Transmission Service or, if coupled with a generating unit external to the PJM Region that satisfies all applicable criteria specified in the PJM Manuals, similar to Capacity Interconnection Rights.

Charge Economic Maximum Megawatts:

"Charge Economic Maximum Megawatts" shall mean the greatest magnitude of megawatt power consumption available for charging in economic dispatch by an Energy Storage Resource Model Participant in Continuous Mode or in Charge Mode. Charge Economic Maximum Megawatts shall be the Economic Minimum for an Energy Storage Resource in Charge Mode or in Continuous Mode.

Charge Economic Minimum Megawatts:

"Charge Economic Minimum Megawatts" shall mean the smallest magnitude of megawatt power consumption available for charging in economic dispatch by an Energy Storage Resource Model Participant in Charge Mode. Charge Economic Minimum Megawatts shall be the Economic Maximum for an Energy Storage Resource in Charge Mode.

Charge Mode:

"Charge Mode" shall mean the mode of operation of an Energy Storage Resource Model Participant that only includes negative megawatt quantities (i.e., the Energy Storage Resource Model Participant is only withdrawing megawatts from the grid).

Charge Ramp Rate:

"Charge Ramp Rate" shall mean the Ramping Capability of an Energy Storage Resource Model Participant in Charge Mode.

Cleared Capacity Resource with State Subsidy:

"Cleared Capacity Resource with State Subsidy" shall mean a Capacity Resource with State Subsidy that has cleared in an RPM Auction for a Prior Delivery Year pursuant to its Sell Offer at or above its resource-specific MOPR Floor Offer Price or the applicable default New Entry MOPR Floor Offer Price. Notwithstanding the foregoing, any Capacity Resource that previously cleared an RPM Auction before it received or became entitled to receive a State Subsidy shall also be deemed a Cleared Capacity Resource with State Subsidy.

Cold/Warm/Hot Notification Time:

"Cold/Warm/Hot Notification Time" shall mean the time interval between PJM notification and the beginning of the start sequence for a generating unit that is currently in its cold/warm/hot temperature state. The start sequence may include steps such as any valve operation, starting feed water pumps, startup of auxiliary equipment, etc.

Cold/Warm/Hot Start-up Time:

For all generating units that are not combined cycle units, "Cold/Warm/Hot Start-up Time" shall mean the time interval, measured in hours, from the beginning of the start sequence to the point after generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero for a generating unit in its cold/warm/hot temperature state. For combined cycle units, "Cold/Warm/Hot Start-up Time" shall mean the time interval from the beginning of the start sequence to the point after first combustion turbine generator breaker closure in its cold/warm/hot temperature state, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero. For all generating units, the start sequence may include steps such as any valve operation, starting feed water pumps, startup of auxiliary equipment, etc. Other more detailed actions that could signal the beginning of the start sequence could include, but are not limited to, the operation of pumps, condensers, fans, water chemistry evaluations, checklists, valves, fuel systems, combustion turbines, starting engines or systems, maintaining stable fuel/air ratios, and other auxiliary equipment necessary for startup.

Cold Weather Alert:

"Cold Weather Alert" shall mean the notice that PJM provides to PJM Members, Transmission Owners, resource owners and operators, customers, and regulators to prepare personnel and facilities for expected extreme cold weather conditions.

Collateral:

"Collateral" shall be a cash deposit, including any interest, or letter of credit in an amount and form determined by and acceptable to PJMSettlement, provided by a Participant to PJMSettlement as security in order to participate in the PJM Markets or take Transmission Service.

Collateral Call:

"Collateral Call" shall mean a notice to a Participant that additional Collateral, or possibly early payment, is required in order to remain in, or to regain, compliance with Tariff, Attachment Q.

Commencement Date:

"Commencement Date" shall mean the date on which Interconnection Service commences in accordance with an Interconnection Service Agreement.

Committed Offer:

The "Committed Offer" shall mean 1) for pool-scheduled resources, an offer on which a resource was scheduled by the Office of the Interconnection for a particular clock hour for an Operating Day, and 2) for self-scheduled resources, either the offer on which the Market Seller has elected to schedule the resource or the applicable offer for the resource determined pursuant to Operating Agreement, Schedule 1, section 6.4, or Operating Agreement, Schedule 1, section 6.6 for a particular clock hour for an Operating Day.

Completed Application:

"Completed Application" shall mean an application that satisfies all of the information and other requirements of the Tariff, including any required deposit.

Compliance Aggregation Area (CAA):

"Compliance Aggregation Area" or "CAA" shall mean a geographic area of Zones or sub-Zones that are electrically-contiguous and experience for the relevant Delivery Year, based on Resource Clearing Prices of, for Delivery Years through May 31, 2018, Annual Resources and for the 2018/2019 Delivery Year and subsequent Delivery Years, Capacity Performance Resources, the same locational price separation in the Base Residual Auction, the same locational price separation in the First Incremental Auction, the same locational price separation in the Second Incremental Auction, the same locational price separation in the Third Incremental Auction.

Conditional Incremental Auction:

"Conditional Incremental Auction" shall mean an Incremental Auction conducted for a Delivery Year if and when necessary to secure commitments of additional capacity to address reliability criteria violations arising from the delay in a Backbone Transmission upgrade that was modeled in the Base Residual Auction for such Delivery Year.

CONE Area:

"CONE Area" shall mean the areas listed in Tariff, Attachment DD, section 5.10(a)(iv)(A) and any LDAs established as CONE Areas pursuant to Tariff, Attachment DD, section 5.10(a)(iv)(B).

Confidential Information:

"Confidential Information" shall mean any confidential, proprietary, or trade secret information of a plan, specification, pattern, procedure, design, device, list, concept, policy, or compilation relating to the present or planned business of a New Service Customer, Transmission Owner, or other Interconnection Party or Construction Party, which is designated as confidential by the party supplying the information, whether conveyed verbally, electronically, in writing, through inspection, or otherwise, and shall include, without limitation, all information relating to the producing party's technology, research and development, business affairs and pricing, and any information supplied by any New Service Customer, Transmission Owner, or other Interconnection Party or Construction Party to another such party prior to the execution of an Interconnection Service Agreement or a Construction Service Agreement.

Congestion Price:

"Congestion Price" shall mean the congestion component of the Locational Marginal Price, which is the effect on transmission congestion costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource, based on the effect of increased generation from or consumption by the resource on transmission line loadings, calculated as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

Consolidated Transmission Owners Agreement, PJM Transmission Owners Agreement or Transmission Owners Agreement:

"Consolidated Transmission Owners Agreement," "PJM Transmission Owners Agreement" or "Transmission Owners Agreement" shall mean the certain Consolidated Transmission Owners Agreement dated as of December 15, 2005, by and among the Transmission Owners and by and between the Transmission Owners and PJM Interconnection, L.L.C. on file with the Commission, as amended from time to time.

Constraint Relaxation Logic:

"Constraint Relaxation Logic" shall mean the logic applied in the market clearing software where the transmission limit is increased to prevent the Transmission Constraint Penalty Factor from setting the Marginal Value of a transmission constraint.

Constructing Entity:

"Constructing Entity" shall mean either the Transmission Owner or the New Services Customer, depending on which entity has the construction responsibility pursuant to Tariff, Part VI and the applicable Construction Service Agreement; this term shall also be used to refer to an Interconnection Customer with respect to the construction of the Customer Interconnection Facilities.

Construction Party:

"Construction Party" shall mean a party to a Construction Service Agreement. "Construction Parties" shall mean all of the Parties to a Construction Service Agreement.

Construction Service Agreement:

"Construction Service Agreement" shall mean either an Interconnection Construction Service Agreement or an Upgrade Construction Service Agreement.

Contingent Facilities:

"Contingent Facilities" shall mean those unbuilt Interconnection Facilities and Network Upgrades upon which the Interconnection Request's costs, timing, and study findings are dependent and, if delayed or not built, could cause a need for restudies of the Interconnection Request or a reassessment of the Interconnection Facilities and/or Network Upgrades and/or costs and timing.

Continuous Mode:

"Continuous Mode" shall mean the mode of operation of an Energy Storage Resource Model Participant that includes both negative and positive megawatt quantities (i.e., the Energy Storage Resource Model Participant is capable of continually and immediately transitioning from withdrawing megawatt quantities from the grid to injecting megawatt quantities onto the grid or injecting megawatts to withdrawing megawatts). Energy Storage Resource Model Participants operating in Continuous Mode are considered to have an unlimited ramp rate. Continuous Mode requires Discharge Economic Maximum Megawatts to be zero or correspond to an injection, and Charge Economic Maximum Megawatts to be zero or correspond to a withdrawal.

Control Area:

“Control Area” shall mean an electric power system or combination of electric power systems bounded by interconnection metering and telemetry to which a common automatic generation control scheme is applied in order to:

(1) match the power output of the generators within the electric power system(s) and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);

(2) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;

(3) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and

(4) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

Control Zone:

“Control Zone” shall have the meaning given in the Operating Agreement.

Controllable A.C. Merchant Transmission Facilities:

“Controllable A.C. Merchant Transmission Facilities” shall mean transmission facilities that (1) employ technology which Transmission Provider reviews and verifies will permit control of the amount and/or direction of power flow on such facilities to such extent as to effectively enable the controllable facilities to be operated as if they were direct current transmission facilities, and (2) that are interconnected with the Transmission System pursuant to Tariff, Part IV and Tariff, Part VI.

Coordinated External Transaction:

“Coordinated External Transaction” shall mean a transaction to simultaneously purchase and sell energy on either side of a CTS Enabled Interface in accordance with the procedures of Operating Agreement, Schedule 1, section 1.13, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.13.

Coordinated Transaction Scheduling:

“Coordinated Transaction Scheduling” or “CTS” shall mean the scheduling of Coordinated External Transactions at a CTS Enabled Interface in accordance with the procedures of Operating Agreement, Schedule 1, section 1.13, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.13.

Corporate Guaranty:

"Corporate Guaranty" shall mean a legal document used by an entity to guaranty the obligations of another entity.

Cost of New Entry:

"Cost of New Entry" or "CONE" shall mean the nominal levelized cost of a Reference Resource, as determined in accordance with Tariff, Attachment DD, section 5.

Costs:

As used in Tariff, Part IV, Tariff, Part VI and related attachments, "Costs" shall mean costs and expenses, as estimated or calculated, as applicable, including, but not limited to, capital expenditures, if applicable, and overhead, return, and the costs of financing and taxes and any Incidental Expenses.

Counterparty:

"Counterparty" shall mean PJMSettlement as the contracting party, in its name and own right and not as an agent, to an agreement or transaction with a Market Participant or other entities, including the agreements and transactions with customers regarding transmission service and other transactions under the PJM Tariff and the Operating Agreement. PJMSettlement shall not be a counterparty to (i) any bilateral transactions between Members, or (ii) any Member's self-supply of energy to serve its load, or (iii) any Member's self-schedule of energy reported to the Office of the Interconnection to the extent that energy serves that Member's own load .

Credit Available for Export Transactions:

"Credit Available for Export Transactions" shall mean a designation of credit to be used for Export Transactions that is allocated by each Market Participant from its Credit Available for Virtual Transactions, and which reduces the Market Participant's Credit Available for Virtual Transactions accordingly.

Credit Available for Virtual Transactions:

"Credit Available for Virtual Transactions" shall mean the Market Participant's Working Credit Limit for Virtual Transactions calculated on its credit provided in compliance with its Peak Market Activity requirement plus available credit submitted above that amount, less any unpaid billed and unbilled amounts owed to PJMSettlement, plus any unpaid unbilled amounts owed by PJMSettlement to the Market Participant, less any applicable credit required for Minimum Participation Requirements, FTRs, RPM activity, or other credit requirement determinants as defined in Tariff, Attachment Q.

Credit Breach:

"Credit Breach" shall mean the status of a Participant that does not currently meet the requirements of Tariff, Attachment Q or other provisions of the Agreements.

Credit-Limited Offer:

"Credit-Limited Offer" shall mean a Sell Offer that is submitted by a Market Participant in an RPM Auction subject to a maximum credit requirement specified by such Market Participant.

Credit Score:

"Credit Score" shall mean a composite numerical score scaled from 0-100 as calculated by PJMSettlement that incorporates various predictors of creditworthiness.

CTS Enabled Interface:

"CTS Enabled Interface" shall mean an interface between the PJM Control Area and an adjacent Control Area at which the Office of the Interconnection has authorized the use of Coordinated Transaction Scheduling ("CTS"). The CTS Enabled Interfaces between the PJM Control Area and the New York Independent System Operator, Inc. Control Area shall be designated in the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C., Schedule A (PJM Rate Schedule FERC No. 45). The CTS Enabled Interfaces between the PJM Control Area and the Midcontinent Independent System Operator, Inc. shall be designated consistent with Attachment 3, section 2 of the Joint Operating Agreement between Midcontinent Independent System Operator, Inc. and PJM Interconnection, L.L.C.

CTS Interface Bid:

"CTS Interface Bid" shall mean a unified real-time bid to simultaneously purchase and sell energy on either side of a CTS Enabled Interface in accordance with the procedures of Operating Agreement, Schedule 1, section 1.13, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.13.

Curtailment:

"Curtailment" shall mean a reduction in firm or non-firm transmission service in response to a transfer capability shortage as a result of system reliability conditions.

Curtailment Service Provider:

"Curtailment Service Provider" or "CSP" shall mean a Member or a Special Member, which action on behalf of itself or one or more other Members or non-Members, participates in the PJM Interchange Energy Market, Ancillary Services markets, and/or Reliability Pricing Model by causing a reduction in demand.

Customer Facility:

“Customer Facility” shall mean Generation Facilities or Merchant Transmission Facilities interconnected with or added to the Transmission System pursuant to an Interconnection Request under Tariff, Part IV.

Customer-Funded Upgrade:

“Customer-Funded Upgrade” shall mean any Network Upgrade, Local Upgrade, or Merchant Network Upgrade for which cost responsibility (i) is imposed on an Interconnection Customer or an Eligible Customer pursuant to Tariff, Part VI, section 217, or (ii) is voluntarily undertaken by a New Service Customer in fulfillment of an Upgrade Request. No Network Upgrade, Local Upgrade or Merchant Network Upgrade or other transmission expansion or enhancement shall be a Customer-Funded Upgrade if and to the extent that the costs thereof are included in the rate base of a public utility on which a regulated return is earned.

Customer Interconnection Facilities:

“Customer Interconnection Facilities” shall mean all facilities and equipment owned and/or controlled, operated and maintained by Interconnection Customer on Interconnection Customer’s side of the Point of Interconnection identified in the appropriate appendices to the Interconnection Service Agreement and to the Interconnection Construction Service Agreement, including any modifications, additions, or upgrades made to such facilities and equipment, that are necessary to physically and electrically interconnect the Customer Facility with the Transmission System.

Daily Deficiency Rate:

“Daily Deficiency Rate” shall mean the rate employed to assess certain deficiency charges under Tariff, Attachment DD, section 7, Tariff, Attachment DD, section 8, Tariff, Attachment DD, section 9, or Tariff, Attachment DD, section 13.

Daily Unforced Capacity Obligation:

“Daily Unforced Capacity Obligation” shall mean the capacity obligation of a Load Serving Entity during the Delivery Year, determined in accordance with Reliability Assurance Agreement, Schedule 8, or, as to an FRR entity, in Reliability Assurance Agreement, Schedule 8.1.

Day-ahead Congestion Price:

“Day-ahead Congestion Price” shall mean the Congestion Price resulting from the Day-ahead Energy Market.

Day-ahead Energy Market:

“Day-ahead Energy Market” shall mean the schedule of commitments for the purchase or sale of energy and payment of Transmission Congestion Charges developed by the Office of the

Interconnection as a result of the offers and specifications submitted in accordance with Operating Agreement, Schedule 1, section 1.10 and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.

Day-ahead Energy Market Injection Congestion Credits:

“Day-ahead Energy Market Injection Congestion Credits” shall mean those congestion credits paid to Market Participants for supply transactions in the Day-ahead Energy Market including generation schedules, Increment Offers, Up-to Congestion Transactions, import transactions, and Day-Ahead Pseudo-Tie Transactions.

Day-ahead Energy Market Transmission Congestion Charges:

“Day-ahead Energy Market Transmission Congestion Charges” shall be equal to the sum of Day-ahead Energy Market Withdrawal Congestion Charges minus [the sum of Day-ahead Energy Market Injection Congestion Credits plus any congestion charges calculated pursuant to the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38), plus any congestion charges calculated pursuant to the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 45), plus any congestion charges calculated pursuant to agreements between the Office of the Interconnection and other entities, as applicable)].

Day-ahead Energy Market Withdrawal Congestion Charges:

“Day-ahead Energy Market Withdrawal Congestion Charges” shall mean those congestion charges collected from Market Participants for withdrawal transactions in the Day-ahead Energy Market from transactions including Demand Bids, Decrement Bids, Up-to Congestion Transactions, Export Transactions, and Day-Ahead Pseudo-Tie Transactions.

Day-ahead Loss Price:

“Day-ahead Loss Price” shall mean the Loss Price resulting from the Day-ahead Energy Market.

Day-ahead Prices:

“Day-ahead Prices” shall mean the Locational Marginal Prices resulting from the Day-ahead Energy Market.

Day-Ahead Pseudo-Tie Transaction:

“Day-Ahead Pseudo-Tie Transaction” shall mean a transaction scheduled in the Day-ahead Energy Market to the PJM-MISO interface from a generator within the PJM balancing authority area that Pseudo-Ties into the MISO balancing authority area.

Day-ahead Scheduling Reserves:

"Day-ahead Scheduling Reserves" shall mean thirty-minute reserves as defined by the Reliability*First* Corporation and SERC.

Day-ahead Scheduling Reserves Market:

"Day-ahead Scheduling Reserves Market" shall mean the schedule of commitments for the purchase or sale of Day-ahead Scheduling Reserves developed by the Office of the Interconnection as a result of the offers and specifications submitted in accordance with Operating Agreement, Schedule 1, section 1.10 and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.

Day-ahead Scheduling Reserves Requirement:

"Day-ahead Scheduling Reserves Requirement" shall mean the sum of Base Day-ahead Scheduling Reserves Requirement and Additional Day-ahead Scheduling Reserves Requirement.

Day-ahead Scheduling Reserves Resources:

"Day-ahead Scheduling Reserves Resources" shall mean synchronized and non-synchronized generation resources and Demand Resources electrically located within the PJM Region that are capable of providing Day-ahead Scheduling Reserves.

Day-ahead Settlement Interval:

"Day-ahead Settlement Interval" shall mean the interval used by settlements, which shall be every one clock hour.

Day-ahead System Energy Price:

"Day-ahead System Energy Price" shall mean the System Energy Price resulting from the Day-ahead Energy Market.

Deactivation:

"Deactivation" shall mean the retirement or mothballing of a generating unit governed by Tariff, Part V.

Deactivation Avoidable Cost Credit:

"Deactivation Avoidable Cost Credit" shall mean the credit paid to Generation Owners pursuant to Tariff, Part V, section 114.

Deactivation Avoidable Cost Rate:

“Deactivation Avoidable Cost Rate” shall mean the formula rate established pursuant to Tariff, Part V, section 115 .

Deactivation Date:

“Deactivation Date” shall mean the date a generating unit within the PJM Region is either retired or mothballed and ceases to operate.

Decrement Bid:

“Decrement Bid” shall mean a type of Virtual Transaction that is a bid to purchase energy at a specified location in the Day-ahead Energy Market. A cleared Decrement Bid results in scheduled load at the specified location in the Day-ahead Energy Market.

Default:

As used in the Interconnection Service Agreement and Construction Service Agreement, “Default” shall mean the failure of a Breaching Party to cure its Breach in accordance with the applicable provisions of an Interconnection Service Agreement or Construction Service Agreement.

Delivering Party:

“Delivering Party” shall mean the entity supplying capacity and energy to be transmitted at Point(s) of Receipt.

Delivery Year:

“Delivery Year” shall mean the Planning Period for which a Capacity Resource is committed pursuant to the auction procedures specified in Tariff, Attachment DD, or pursuant to an FRR Capacity Plan under Reliability Assurance Agreement, Schedule 8.1.

Demand Bid:

“Demand Bid” shall mean a bid, submitted by a Load Serving Entity in the Day-ahead Energy Market, to purchase energy at its contracted load location, for a specified timeframe and megawatt quantity, that if cleared will result in energy being scheduled at the specified location in the Day-ahead Energy Market and in the physical transfer of energy during the relevant Operating Day.

Demand Bid Limit:

“Demand Bid Limit” shall mean the largest MW volume of Demand Bids that may be submitted by a Load Serving Entity for any hour of an Operating Day, as determined pursuant to Operating Agreement, Schedule 1, section 1.10.1B, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.1B.

Demand Bid Screening:

"Demand Bid Screening" shall mean the process by which Demand Bids are reviewed against the applicable Demand Bid Limit, and rejected if they would exceed that limit, as determined pursuant to Operating Agreement, Schedule 1, section 1.10.1B, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.1B.

Demand Resource:

"Demand Resource" shall mean a resource with the capability to provide a reduction in demand.

Demand Resource Factor or DR Factor:

"Demand Resource Factor" or ("DR Factor") shall have the meaning specified in the Reliability Assurance Agreement.

Designated Agent:

"Designated Agent" shall mean any entity that performs actions or functions on behalf of the Transmission Provider, a Transmission Owner, an Eligible Customer, or the Transmission Customer required under the Tariff.

Designated Entity:

"Designated Entity" shall have the same meaning provided in the Operating Agreement.

Direct Assignment Facilities:

"Direct Assignment Facilities" shall mean facilities or portions of facilities that are constructed for the sole use/benefit of a particular Transmission Customer requesting service under the Tariff. Direct Assignment Facilities shall be specified in the Service Agreement that governs service to the Transmission Customer and shall be subject to Commission approval.

Direct Charging Energy:

"Direct Charging Energy" shall mean the energy that an Energy Storage Resource purchases from the PJM Interchange Energy Market and (i) later resells to the PJM Interchange Energy Market; or (ii) is lost to conversion inefficiencies, provided that such inefficiencies are an unavoidable component of the conversion, storage, and discharge process that is used to resell energy back to the PJM Interchange Energy Market.

Direct Load Control:

"Direct Load Control" shall mean load reduction that is controlled directly by the Curtailment Service Provider's market operations center or its agent, in response to PJM instructions.

Discharge Economic Maximum Megawatts:

"Discharge Economic Maximum Megawatts" shall mean the maximum megawatt power output available for discharge in economic dispatch by an Energy Storage Resource Model Participant in Continuous Mode or in Discharge Mode. Discharge Economic Maximum Megawatts shall be the Economic Maximum for an Energy Storage Resource in Discharge Mode or in Continuous Mode.

Discharge Economic Minimum Megawatts:

"Discharge Economic Minimum Megawatts" shall mean the minimum megawatt power output available for discharge in economic dispatch by an Energy Storage Resource Model Participant in Discharge Mode. Discharge Economic Minimum Megawatts shall be the Economic Minimum for an Energy Storage Resource in Discharge Mode.

Discharge Mode:

"Discharge Mode" shall mean the mode of operation of an Energy Storage Resource Model Participant that only includes positive megawatt quantities (i.e., the Energy Storage Resource Model Participant is only injecting megawatts onto the grid).

Discharge Ramp Rate*:*

"Discharge Ramp Rate" shall mean the Ramping Capability of an Energy Storage Resource Model Participant in Discharge Mode.

Dispatch Rate:

"Dispatch Rate" shall mean the control signal, expressed in dollars per megawatt-hour, calculated and transmitted continuously and dynamically to direct the output level of all generation resources dispatched by the Office of the Interconnection in accordance with the Offer Data.

Dispatched Charging Energy:

"Dispatched Charging Energy" shall mean Direct Charging Energy that an Energy Storage Resource Model Participant receives from the electric grid pursuant to PJM dispatch while providing *one of the following* services in the PJM markets*: Energy Imbalance Service pursuant to Tariff, Schedule 4; Regulation; Tier 2 Synchronized Reserves; or Reactive Service. Energy Storage Resource Model Participants shall be considered to be providing Energy Imbalance Service when they are dispatchable by PJM in real-time.*

Dynamic Schedule:

"Dynamic Schedule" shall have the same meaning provided in the Operating Agreement.

Dynamic Transfer:

"Dynamic Transfer" shall have the same meaning provided in the Operating Agreement.

Definitions – I – J - K

IDR Transfer Agreement:

"IDR Transfer Agreement" shall mean an agreement to transfer, subject to the terms of Tariff, Part VI, section 237, Incremental Deliverability Rights to a party for the purpose of eliminating or reducing the need for Local or Network Upgrades that would otherwise have been the responsibility of the party receiving such rights.

Immediate-need Reliability Project:

"Immediate-need Reliability Project" shall have the same meaning provided in the Operating Agreement.

Inadvertent Interchange:

"Inadvertent Interchange" shall mean the difference between net actual energy flow and net scheduled energy flow into or out of the individual Control Areas operated by PJM.

Incidental Expenses:

"Incidental Expenses" shall mean those expenses incidental to the performance of construction pursuant to an Interconnection Construction Service Agreement, including, but not limited to, the expense of temporary construction power, telecommunications charges, Interconnected Transmission Owner expenses associated with, but not limited to, document preparation, design review, installation, monitoring, and construction-related operations and maintenance for the Customer Facility and for the Interconnection Facilities.

Incremental Auction:

"Incremental Auction" shall mean any of several auctions conducted for a Delivery Year after the Base Residual Auction for such Delivery Year and before the first day of such Delivery Year, including the First Incremental Auction, Second Incremental Auction, Third Incremental Auction or Conditional Incremental Auction. Incremental Auctions (other than the Conditional Incremental Auction shall be held for the purposes of:

(i) allowing Market Sellers that committed Capacity Resources in the Base Residual Auction for a Delivery Year, which subsequently are determined to be unavailable to deliver the committed Unforced Capacity in such Delivery Year (due to resource retirement, resource cancellation or construction delay, resource derating, EFORd increase, a decrease in the Nominated Demand Resource Value of a Planned Demand Resource, delay or cancellation of a Qualifying Transmission Upgrade, or similar occurrences) to submit Buy Bids for replacement Capacity Resources; and

(ii) allowing the Office of the Interconnection to reduce or increase the amount of committed capacity secured in prior auctions for such Delivery Year if, as a result of changed circumstances or expectations since the prior auction(s), there is, respectively, a significant excess or significant deficit of committed capacity for such Delivery Year, for the PJM Region or for an LDA.

Incremental Auction Revenue Rights:

"Incremental Auction Revenue Rights" shall mean the additional Auction Revenue Rights, not previously feasible, created by the addition of Incremental Rights-Eligible Required Transmission Enhancements, Merchant Transmission Facilities, or of one or more Customer-Funded Upgrades.

Incremental Available Transfer Capability Revenue Rights:

"Incremental Available Transfer Capability Revenue Rights" shall mean the rights to revenues that are derived from incremental Available Transfer Capability created by the addition of Merchant Transmission Facilities or of one of more Customer-Funded Upgrades.

Incremental Capacity Transfer Right:

"Incremental Capacity Transfer Right" shall mean a Capacity Transfer Right allocated to a Generation Interconnection Customer or Transmission Interconnection Customer obligated to fund a transmission facility or upgrade, to the extent such upgrade or facility increases the transmission import capability into a Locational Deliverability Area, or a Capacity Transfer Right allocated to a Responsible Customer in accordance with Tariff, Schedule 12A.

Incremental Deliverability Rights (IDRs):

"Incremental Deliverability Rights" or "IDRs" shall mean the rights to the incremental ability, resulting from the addition of Merchant Transmission Facilities, to inject energy and capacity at a point on the Transmission System, such that the injection satisfies the deliverability requirements of a Capacity Resource. Incremental Deliverability Rights may be obtained by a generator or a Generation Interconnection Customer, pursuant to an IDR Transfer Agreement, to satisfy, in part, the deliverability requirements necessary to obtain Capacity Interconnection Rights.

Incremental Energy Offer:

"Incremental Energy Offer" shall mean offer segments comprised of a pairing of price (in dollars per MWh) and megawatt quantities, which must be a non-decreasing function and taken together produce all of the energy segments above a resource's Economic Minimum. No-load Costs are not included in the Incremental Energy Offer.

Incremental Multi-Driver Project:

"Incremental Multi-Driver Project" shall have the same meaning provided in the Operating Agreement.

Incremental Rights-Eligible Required Transmission Enhancements:

"Incremental Rights-Eligible Required Transmission Enhancements" shall mean Regional Facilities and Necessary Lower Voltage Facilities or Lower Voltage Facilities (as defined in Tariff, Schedule 12) and meet one of the following criteria: (1) cost responsibility is assigned to non-contiguous Zones that are not directly electrically connected; or (2) cost responsibility is assigned to Merchant Transmission Providers that are Responsible Customers.

Increment Offer:

"Increment Offer" shall mean a type of Virtual Transaction that is an offer to sell energy at a specified location in the Day-ahead Energy Market. A cleared Increment Offer results in scheduled generation at the specified location in the Day-ahead Energy Market.

Initial Operation:

"Initial Operation" shall mean the commencement of operation of the Customer Facility and Customer Interconnection Facilities after satisfaction of the conditions of Tariff, Attachment O-Appendix 2, section 1.4 (an Interconnection Service Agreement).

Interconnected Entity:

"Interconnected Entity" shall mean either the Interconnection Customer or the Interconnected Transmission Owner; Interconnected Entities shall mean both of them.

Interconnected Transmission Owner:

"Interconnected Transmission Owner" shall mean the Transmission Owner to whose transmission facilities or distribution facilities Customer Interconnection Facilities are, or as the case may be, a Customer Facility is, being directly connected. When used in an Interconnection Construction Service Agreement, the term may refer to a Transmission Owner whose facilities must be upgraded pursuant to the Facilities Study, but whose facilities are not directly interconnected with those of the Interconnection Customer.

Interconnection Construction Service Agreement:

"Interconnection Construction Service Agreement" shall mean the agreement entered into by an Interconnection Customer, Interconnected Transmission Owner and the Transmission Provider pursuant to Tariff, Part VI, Subpart B and in the form set forth in Tariff, Attachment P, relating to construction of Attachment Facilities, Network Upgrades, and/or Local Upgrades and coordination of the construction and interconnection of an associated Customer Facility. A separate Interconnection Construction Service Agreement will be executed with each Transmission Owner that is responsible for construction of any Attachment Facilities, Network Upgrades, or Local Upgrades associated with interconnection of a Customer Facility.

Interconnection Customer:

"Interconnection Customer" shall mean a Generation Interconnection Customer and/or a Transmission Interconnection Customer.

Interconnection Facilities:

"Interconnection Facilities" shall mean the Transmission Owner Interconnection Facilities and the Customer Interconnection Facilities.

Interconnection Feasibility Study:

"Interconnection Feasibility Study" shall mean either a Generation Interconnection Feasibility Study or Transmission Interconnection Feasibility Study.

Interconnection Party:

"Interconnection Party" shall mean a Transmission Provider, Interconnection Customer, or the Interconnected Transmission Owner. Interconnection Parties shall mean all of them.

Interconnection Request:

"Interconnection Request" shall mean a Generation Interconnection Request, a Transmission Interconnection Request and/or an IDR Transfer Agreement.

Interconnection Service:

"Interconnection Service" shall mean the physical and electrical interconnection of the Customer Facility with the Transmission System pursuant to the terms of Tariff, Part IV and Tariff, Part VI and the Interconnection Service Agreement entered into pursuant thereto by Interconnection Customer, the Interconnected Transmission Owner and Transmission Provider.

Interconnection Service Agreement:

"Interconnection Service Agreement" shall mean an agreement among the Transmission Provider, an Interconnection Customer and an Interconnected Transmission Owner regarding interconnection under Tariff, Part IV and Tariff, Part VI.

Interconnection Studies:

"Interconnection Studies" shall mean the Interconnection Feasibility Study, the System Impact Study, and the Facilities Study described in Tariff, Part IV and Tariff, Part VI.

Interface Pricing Point:

"Interface Pricing Point" shall have the meaning specified in Operating Agreement, Schedule 1, section 2.6A, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.6A.

Intermittent Resource:

"Intermittent Resource" shall mean a Generation Capacity Resource with output that can vary as a function of its energy source, such as wind, solar, run of river hydroelectric power and other renewable resources.

Internal Market Buyer:

"Internal Market Buyer" shall mean a Market Buyer making purchases of energy from the PJM Interchange Energy Market for ultimate consumption by end-users inside the PJM Region that are served by Network Transmission Service.

Interregional Transmission Project:

"Interregional Transmission Project" shall mean transmission facilities that would be located within two or more neighboring transmission planning regions and are determined by each of those regions to be a more efficient or cost effective solution to regional transmission needs.

Interruption:

"Interruption" shall mean a reduction in non-firm transmission service due to economic reasons pursuant to Tariff, Part II, section 14.7.

Jointly Owned Cross-Subsidized Capacity Resource:

"Jointly Owned Cross-Subsidized Capacity Resource" shall mean a Capacity Resource that is supported by a facility that is jointly owned, where at least one owner is entitled to or receives a State Subsidy associated with such Capacity Resource, and therefore shall be considered a Capacity Resource with State Subsidy; provided however, in the event that the material rights and obligations of such generating facility are in pari passu, meaning that such rights and obligations are allocated among the owners pro rata based on ownership share, only Capacity Resources of those owners entitled to receive or receiving a State Subsidy shall have their share of such resource considered a Capacity Resource with a State Subsidy and Capacity Resources of owners not entitled to a State Subsidy shall not be considered a Capacity Resource with a State Subsidy. Each of these designations may be overcome by either Capacity Market Seller demonstrating to the Office of Interconnection, with advice and input from the Market Monitoring Unit, that there is no cross-subsidization or the Office of the Interconnection, with review and input from the Market Monitor, finds based on sufficient evidence, that there is cross-subsidization.

Definitions – L – M – N

Limited Demand Resource:

"Limited Demand Resource**"** shall have the meaning specified in the Reliability Assurance Agreement.

Limited Demand Resource Reliability Target:

"Limited Demand Resource Reliability Target**"** for the PJM Region or an LDA, shall mean the maximum amount of Limited Demand Resources determined by PJM to be consistent with the maintenance of reliability, stated in Unforced Capacity that shall be used to calculate the Minimum Extended Summer Demand Resource Requirement for Delivery Years through May 31, 2017 and the Limited Resource Constraint for the 2017/2018 and 2018/2019 Delivery Years for the PJM Region or such LDA. As more fully set forth in the PJM Manuals, PJM calculates the Limited Demand Resource Reliability Target by first: i) testing the effects of the ten-interruption requirement by comparing possible loads on peak days under a range of weather conditions (from the daily load forecast distributions for the Delivery Year in question) against possible generation capacity on such days under a range of conditions (using the cumulative capacity distributions employed in the Installed Reserve Margin study for the PJM Region and in the Capacity Emergency Transfer Objective study for the relevant LDAs for such Delivery Year) and, by varying the assumed amounts of DR that is committed and displaces committed generation, determines the DR penetration level at which there is a ninety percent probability that DR will not be called (based on the applicable operating reserve margin for the PJM Region and for the relevant LDAs) more than ten times over those peak days; ii) testing the six-hour duration requirement by calculating the MW difference between the highest hourly unrestricted peak load and seventh highest hourly unrestricted peak load on certain high peak load days (e.g., the annual peak, loads above the weather normalized peak, or days where load management was called) in recent years, then dividing those loads by the forecast peak for those years and averaging the result; and (iii) (for the 2016/2017 and 2017/2018 Delivery Years) testing the effects of the six-hour duration requirement by comparing possible hourly loads on peak days under a range of weather conditions (from the daily load forecast distributions for the Delivery Year in question) against possible generation capacity on such days under a range of conditions (using a Monte Carlo model of hourly capacity levels that is consistent with the capacity model employed in the Installed Reserve Margin study for the PJM Region and in the Capacity Emergency Transfer Objective study for the relevant LDAs for such Delivery Year) and, by varying the assumed amounts of DR that is committed and displaces committed generation, determines the DR penetration level at which there is a ninety percent probability that DR will not be called (based on the applicable operating reserve margin for the PJM Region and for the relevant LDAs) for more than six hours over any one or more of the tested peak days. Second, PJM adopts the lowest result from these three tests as the Limited Demand Resource Reliability Target. The Limited Demand Resource Reliability Target shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the DR Factor] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

Limited Resource Constraint:

"Limited Resource Constraint" shall mean, for the 2017/2018 Delivery Year and for FRR Capacity Plans the 2017/2018 and Delivery Years, for the PJM Region or each LDA for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for a Delivery Year, a limit on the total amount of Unforced Capacity that can be committed as Limited Demand Resources for the 2017/2018 Delivery Year in the PJM Region or in such LDA, calculated as the Limited Demand Resource Reliability Target for the PJM Region or such LDA, respectively, minus the Short Term Resource Procurement Target for the PJM Region or such LDA, respectively.

Limited Resource Price Decrement:
"Limited Resource Price Decrement" shall mean, for the 2017/2018 Delivery Year, a difference between the clearing price for Limited Demand Resources and the clearing price for Extended Summer Demand Resources and Annual Resources, representing the cost to procure additional Extended Summer Demand Resources or Annual Resources out of merit order when the Limited Resource Constraint is binding.

List of Approved Contractors:

"List of Approved Contractors" shall mean a list developed by each Transmission Owner and published in a PJM Manual of (a) contractors that the Transmission Owner considers to be qualified to install or construct new facilities and/or upgrades or modifications to existing facilities on the Transmission Owner's system, provided that such contractors may include, but need not be limited to, contractors that, in addition to providing construction services, also provide design and/or other construction-related services, and (b) manufacturers or vendors of major transmission-related equipment (e.g., high-voltage transformers, transmission line, circuit breakers) whose products the Transmission Owner considers acceptable for installation and use on its system.

Load Management:

"Load Management" shall mean a Demand Resource ("DR") as defined in the Reliability Assurance Agreement.

Load Management Event:

"Load Management Event" shall mean a) a single temporally contiguous dispatch of Demand Resources in a Compliance Aggregation Area during an Operating Day, or b) multiple dispatches of Demand Resources in a Compliance Aggregation Area during an Operating Day that are temporally contiguous.

Load Ratio Share:

"Load Ratio Share" shall mean the ratio of a Transmission Customer's Network Load to the Transmission Provider's total load.

Load Reduction Event:

"Load Reduction Event" shall mean a reduction in demand by a Member or Special Member for the purpose of participating in the PJM Interchange Energy Market.

Load Serving Charging Energy:

"Load Serving Charging Energy" shall mean energy that is purchased from the PJM Interchange Energy Market and stored in an Energy Storage Resource for later resale to end-use load.

Load Serving Entity (LSE):

"Load Serving Entity" or "LSE" shall have the meaning specified in the Reliability Assurance Agreement.

Load Shedding:

"Load Shedding" shall mean the systematic reduction of system demand by temporarily decreasing load in response to transmission system or area capacity shortages, system instability, or voltage control considerations under Tariff, Part II or Part III.

Local Upgrades:

"Local Upgrades" shall mean modifications or additions of facilities to abate any local thermal loading, voltage, short circuit, stability or similar engineering problem caused by the interconnection and delivery of generation to the Transmission System. Local Upgrades shall include:

(i) Direct Connection Local Upgrades which are Local Upgrades that only serve the Customer Interconnection Facility and have no impact or potential impact on the Transmission System until the final tie-in is complete; and

(ii) Non-Direct Connection Local Upgrades which are parallel flow Local Upgrades that are not Direct Connection Local Upgrades.

Location:

"Location" as used in the Economic Load Response rules shall mean an end-use customer site as defined by the relevant electric distribution company account number.

LOC Deviation:

"LOC Deviation," shall mean, for units other than wind units, the LOC Deviation shall equal the desired megawatt amount for the resource determined according to the point on the Final Offer curve corresponding to the Real-time Settlement Interval real-time Locational Marginal Price at the resource's bus and adjusted for any Regulation or Tier 2 Synchronized Reserve assignments and limited to the lesser of the unit's Economic Maximum or the unit's Generation Resource Maximum Output, minus the actual output of the unit. For wind units, the LOC Deviation shall mean the deviation of the generating unit's output equal to the lesser of the PJM forecasted output for the unit or the desired megawatt amount for the resource determined according to the point on the Final Offer curve corresponding to the Real-time Settlement Interval integrated real-time Locational Marginal Price at the resource's bus, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Generation Resource Maximum Output, minus the actual output of the unit.

Locational Deliverability Area (LDA):

"Locational Deliverability Area" or "LDA" shall mean a geographic area within the PJM Region that has limited transmission capability to import capacity to satisfy such area's reliability requirement, as determined by the Office of the Interconnection in connection with preparation of the Regional Transmission Expansion Plan, and as specified in Reliability Assurance Agreement, Schedule 10.1.

Locational Deliverability Area Reliability Requirement:

"Locational Deliverability Area Reliability Requirement" shall mean the projected internal capacity in the Locational Deliverability Area plus the Capacity Emergency Transfer Objective for the Delivery Year, as determined by the Office of the Interconnection in connection with preparation of the Regional Transmission Expansion Plan, less the minimum internal resources required for all FRR Entities in such Locational Deliverability Area.

Locational Price Adder:

"Locational Price Adder" shall mean an addition to the marginal value of Unforced Capacity within an LDA as necessary to reflect the price of Capacity Resources required to relieve applicable binding locational constraints.

Locational Reliability Charge:

"Locational Reliability Charge" shall have the meaning specified in the Reliability Assurance Agreement.

Locational UCAP:

"Locational UCAP" shall mean unforced capacity that a Member with available uncommitted capacity sells in a bilateral transaction to a Member that previously committed capacity through an RPM Auction but now requires replacement capacity to fulfill its RPM Auction commitment.

The Locational UCAP Seller retains responsibility for performance of the resource providing such replacement capacity.

Locational UCAP Seller:

"Locational UCAP Seller" shall mean a Member that sells Locational UCAP.

Long-lead Project:

"Long-lead Project" shall have the same meaning provided in the Operating Agreement.

Long-Term Firm Point-To-Point Transmission Service:

"Long-Term Firm Point-To-Point Transmission Service" shall mean firm Point-To-Point Transmission Service under Tariff, Part II with a term of one year or more.

Loss Price:

"Loss Price" shall mean the loss component of the Locational Marginal Price, which is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource based on the effect of increased generation from or consumption by the resource on transmission losses, calculated as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

M2M Flowgate:

"M2M Flowgate" shall have the meaning provided in the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.

Maintenance Adder:

"Maintenance Adder" shall mean an adder that may be included to account for variable operation and maintenance expenses in a Market Seller's Fuel Cost Policy. The Maintenance Adder is calculated in accordance with the applicable provisions of PJM Manual 15, and may only include expenses incurred as a result of electric production.

Manual Load Dump Action:

"Manual Load Dump Action" shall mean an Operating Instruction, as defined by NERC, from PJM to shed firm load when the PJM Region cannot provide adequate capacity to meet the PJM Region's load and tie schedules, or to alleviate critically overloaded transmission lines or other equipment.

Manual Load Dump Warning:

"Manual Load Dump Warning" shall mean a notification from PJM to warn Members of an increasingly critical condition of present operations that may require manually shedding load.

Marginal Value:

"Marginal Value" shall mean the incremental change in system dispatch costs, measured as a $/MW value incurred by providing one additional MW of relief to the transmission constraint.

Market Monitor:

"Market Monitor**"** means the head of the Market Monitoring Unit.

Market Monitoring Unit or MMU:

"Market Monitoring Unit" or "MMU" means the independent Market Monitoring Unit defined in 18 CFR § 35.28(a)(7) and established under the PJM Market Monitoring Plan (Attachment M) to the PJM Tariff that is responsible for implementing the Market Monitoring Plan, including the Market Monitor. The Market Monitoring Unit may also be referred to as the IMM or Independent Market Monitor for PJM

Market Monitoring Unit Advisory Committee or MMU Advisory Committee:

"Market Monitoring Unit Advisory Committee" or "MMU Advisory Committee" shall mean the committee established under Tariff, Attachment M, section III.H.

Market Operations Center:

"Market Operations Center" shall mean the equipment, facilities and personnel used by or on behalf of a Market Participant to communicate and coordinate with the Office of the Interconnection in connection with transactions in the PJM Interchange Energy Market or the operation of the PJM Region.

Market Participant:

"Market Participant" shall mean a Market Buyer, a Market Seller, an Economic Load Response Participant, or all three, except when such term is used in Tariff, Attachment M, in which case Market Participant shall mean an entity that generates, transmits, distributes, purchases, or sells electricity, ancillary services, or any other product or service provided under the PJM Tariff or Operating Agreement within, into, out of, or through the PJM Region, but it shall not include an Authorized Government Agency that consumes energy for its own use but does not purchase or sell energy at wholesale.

Market Participant Energy Injection:

“Market Participant Energy Injection” shall mean transactions in the Day-ahead Energy Market and Real-time Energy Market, including but not limited to Day-ahead generation schedules, real-time generation output, Increment Offers, internal bilateral transactions and import transactions, as further described in the PJM Manuals.

Market Participant Energy Withdrawal:

“Market Participant Energy Withdrawal” shall mean transactions in the Day-ahead Energy Market and Real-time Energy Market, including but not limited to Demand Bids, Decrement Bids, real-time load (net of Behind The Meter Generation expected to be operating, but not to be less than zero), internal bilateral transactions and Export Transactions, as further described in the PJM Manuals.

Market Seller Offer Cap:

“Market Seller Offer Cap” shall mean a maximum offer price applicable to certain Market Sellers under certain conditions, as determined in accordance with Tariff, Attachment DD. section 6 and Tariff, Attachment M-Appendix, section II.E.

Market Violation:

“Market Violation” shall mean a tariff violation, violation of a Commission-approved order, rule or regulation, market manipulation, or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies, as defined in 18 C.F.R. § 35.28(b)(8).

Material Modification:

“Material Modification” shall mean any modification to an Interconnection Request that has a material adverse effect on the cost or timing of Interconnection Studies related to, or any Network Upgrades or Local Upgrades needed to accommodate, any Interconnection Request with a later Queue Position.

Maximum Daily Starts:

“Maximum Daily Starts” shall mean the maximum number of times that a generating unit can be started in an Operating Day under normal operating conditions.

Maximum Emergency:

“Maximum Emergency” shall mean the designation of all or part of the output of a generating unit for which the designated output levels may require extraordinary procedures and therefore are available to the Office of the Interconnection only when the Office of the Interconnection declares a Maximum Generation Emergency and requests generation designated as Maximum Emergency to run. The Office of the Interconnection shall post on the PJM website the aggregate amount of megawatts that are classified as Maximum Emergency.

Maximum Facility Output:

"Maximum Facility Output" shall mean the maximum (not nominal) net electrical power output in megawatts, specified in the Interconnection Service Agreement, after supply of any parasitic or host facility loads, that a Generation Interconnection Customer's Customer Facility is expected to produce, provided that the specified Maximum Facility Output shall not exceed the output of the proposed Customer Facility that Transmission Provider utilized in the System Impact Study.

Maximum Generation Emergency:

"Maximum Generation Emergency" shall mean an Emergency declared by the Office of the Interconnection to address either a generation or transmission emergency in which the Office of the Interconnection anticipates requesting one or more Generation Capacity Resources, or Non-Retail Behind The Meter Generation resources to operate at its maximum net or gross electrical power output, subject to the equipment stress limits for such Generation Capacity Resource or Non-Retail Behind The Meter resource in order to manage, alleviate, or end the Emergency.

Maximum Generation Emergency Alert:

"Maximum Generation Emergency Alert" shall mean an alert issued by the Office of the Interconnection to notify PJM Members, Transmission Owners, resource owners and operators, customers, and regulators that a Maximum Generation Emergency may be declared, for any Operating Day in either, as applicable, the Day-ahead Energy Market or the Real-time Energy Market, for all or any part of such Operating Day.

Maximum Run Time:

"Maximum Run Time" shall mean the maximum number of hours a generating unit can run over the course of an Operating Day, as measured by PJM's State Estimator.

Maximum Weekly Starts:

"Maximum Weekly Starts" shall mean the maximum number of times that a generating unit can be started in one week, defined as the 168 hour period starting Monday 0001 hour, under normal operating conditions.

Member:

"Member" shall have the meaning provided in the Operating Agreement.

Merchant A.C. Transmission Facilities:

"Merchant A.C. Transmission Facility" shall mean Merchant Transmission Facilities that are alternating current (A.C.) transmission facilities, other than those that are Controllable A.C. Merchant Transmission Facilities.

Merchant D.C. Transmission Facilities:

"Merchant D.C. Transmission Facilities" shall mean direct current (D.C.) transmission facilities that are interconnected with the Transmission System pursuant to Tariff, Part IV and Part VI.

Merchant Network Upgrades:

"Merchant Network Upgrades" shall mean additions to, or modifications or replacements of, physical facilities of the Interconnected Transmission Owner that, on the date of the pertinent Transmission Interconnection Customer's Upgrade Request, are part of the Transmission System or are included in the Regional Transmission Expansion Plan.

Merchant Transmission Facilities:

"Merchant Transmission Facilities" shall mean A.C. or D.C. transmission facilities that are interconnected with or added to the Transmission System pursuant to Tariff, Part IV and Part VI and that are so identified in Tariff, Attachment T, provided, however, that Merchant Transmission Facilities shall not include (i) any Customer Interconnection Facilities, (ii) any physical facilities of the Transmission System that were in existence on or before March 20, 2003 ; (iii) any expansions or enhancements of the Transmission System that are not identified as Merchant Transmission Facilities in the Regional Transmission Expansion Plan and Attachment T to the Tariff, or (iv) any transmission facilities that are included in the rate base of a public utility and on which a regulated return is earned.

Merchant Transmission Provider:

"Merchant Transmission Provider" shall mean an Interconnection Customer that (1) owns, controls, or controls the rights to use the transmission capability of, Merchant D.C. Transmission Facilities and/or Controllable A.C. Merchant Transmission Facilities that connect the Transmission System with another control area, (2) has elected to receive Transmission Injection Rights and Transmission Withdrawal Rights associated with such facility pursuant to Tariff, Part IV, section 36, and (3) makes (or will make) the transmission capability of such facilities available for use by third parties under terms and conditions approved by the Commission and stated in the Tariff, consistent with Tariff, section 38.

Metering Equipment:

"Metering Equipment" shall mean all metering equipment installed at the metering points designated in the appropriate appendix to an Interconnection Service Agreement.

Minimum Annual Resource Requirement:

"Minimum Annual Resource Requirement" shall mean, for Delivery Years through May 31, 2017, the minimum amount of capacity that PJM will seek to procure from Annual Resources for the PJM Region and for each Locational Deliverability Area for which the Office of the

Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for such Delivery Year. For the PJM Region, the Minimum Annual Resource Requirement shall be equal to the RTO Reliability Requirement minus [the Sub-Annual Resource Reliability Target for the RTO in Unforced Capacity]. For an LDA, the Minimum Annual Resource Requirement shall be equal to the LDA Reliability Requirement minus [the LDA CETL] minus [the Sub-Annual Resource Reliability Target for such LDA in Unforced Capacity]. The LDA CETL may be adjusted pro rata for the amount of load served under the FRR Alternative.

Minimum Down Time:

For all generating units that are not combined cycle units, “Minimum Down Time” shall mean the minimum number of hours under normal operating conditions between unit shutdown and unit startup, calculated as the shortest time difference between the unit’s generator breaker opening and after the unit’s generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero. For combined cycle units, “Minimum Down Time” shall mean the minimum number of hours between the last generator breaker opening and after first combustion turbine generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero.

Minimum Extended Summer Resource Requirement:

“Minimum Extended Summer Resource Requirement” shall mean, for Delivery Years through May 31, 2017, the minimum amount of capacity that PJM will seek to procure from Extended Summer Demand Resources and Annual Resources for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for such Delivery Year. For the PJM Region, the Minimum Extended Summer Resource Requirement shall be equal to the RTO Reliability Requirement minus [the Limited Demand Resource Reliability Target for the PJM Region in Unforced Capacity]. For an LDA, the Minimum Extended Summer Resource Requirement shall be equal to the LDA Reliability Requirement minus [the LDA CETL] minus [the Limited Demand Resource Reliability Target for such LDA in Unforced Capacity]. The LDA CETL may be adjusted pro rata for the amount of load served under the FRR Alternative.

Minimum Generation Emergency:

“Minimum Generation Emergency” shall mean an Emergency declared by the Office of the Interconnection in which the Office of the Interconnection anticipates requesting one or more generating resources to operate at or below Normal Minimum Generation, in order to manage, alleviate, or end the Emergency.

Minimum Participation Requirements:

“Minimum Participation Requirements” shall mean a set of minimum training, risk management, communication and capital or collateral requirements required for Participants in the PJM Markets, as set forth herein and in the Form of Annual Certification set forth as Tariff, Attachment Q, Appendix 1. Participants transacting in FTRs in certain circumstances will be required to demonstrate additional risk management procedures and controls as further set forth in the Annual Certification found in Tariff, Attachment Q, Appendix 1.

Minimum Run Time:

For all generating units that are not combined cycle units, "Minimum Run Time" shall mean the minimum number of hours a unit must run, in real-time operations, from the time after generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero, to the time of generator breaker opening, as measured by PJM's State Estimator. For combined cycle units, "Minimum Run Time" shall mean the time period after the first combustion turbine generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero, and the last generator breaker opening as measured by PJM's State Estimator.

MISO:

"MISO" shall mean the Midcontinent Independent System Operator, Inc. or any successor thereto.

MOPR Floor Offer Price:

"MOPR Floor Offer Price" shall mean a minimum offer price applicable to certain Market Seller's Capacity Resources under certain conditions, as determined in accordance with Tariff, Attachment DD. section 5.14(h).

Multi-Driver Project:

"Multi-Driver Project" shall have the same meaning provided in the Operating Agreement.

Native Load Customers:

"Native Load Customers" shall mean the wholesale and retail power customers of a Transmission Owner on whose behalf the Transmission Owner, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate the Transmission Owner's system to meet the reliable electric needs of such customers.

NERC:

"NERC" shall mean the North American Electric Reliability Corporation or any successor thereto.

NERC Interchange Distribution Calculator:

"NERC Interchange Distribution Calculator" shall mean the NERC mechanism that is in effect and being used to calculate the distribution of energy, over specific transmission interfaces, from energy transactions.

Net Benefits Test:

"Net Benefits Test" shall mean a calculation to determine whether the benefits of a reduction in price resulting from the dispatch of Economic Load Response exceeds the cost to other loads resulting from the billing unit effects of the load reduction, as specified in Operating Agreement, Schedule 1, section 3.3A.4 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.4.

Net Cost of New Entry:

"Net Cost of New Entry" shall mean the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset.

Net Obligation:

"Net Obligation" shall mean the amount owed to PJMSettlement and PJM for purchases from the PJM Markets, Transmission Service, (under Tariff, Parts II and III , and other services pursuant to the Agreements, after applying a deduction for amounts owed to a Participant by PJMSettlement as it pertains to monthly market activity and services. Should other markets be formed such that Participants may incur future Obligations in those markets, then the aggregate amount of those Obligations will also be added to the Net Obligation.

Net Sell Position:

"Net Sell Position" shall mean the amount of Net Obligation when Net Obligation is negative.

Network Customer:

"Network Customer" shall mean an entity receiving transmission service pursuant to the terms of the Transmission Provider's Network Integration Transmission Service under Tariff, Part III.

Network External Designated Transmission Service:

"Network External Designated Transmission Service" shall have the meaning set forth in Reliability Assurance Agreement, Article I.

Network Integration Transmission Service:

"Network Integration Transmission Service" shall mean the transmission service provided under Tariff, Part III.

Network Load:

"Network Load" shall mean the load that a Network Customer designates for Network Integration Transmission Service under Tariff, Part III. The Network Customer's Network Load shall include all load (including losses, Non-Dispatched Charging Energy, and Load Serving Charging Energy) served by the output of any Network Resources designated by the Network Customer. A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery. Where an Eligible Customer has elected not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangements under Tariff, Part II for any Point-To-Point Transmission Service that may be necessary for such non-designated load. Network Load shall not include Dispatched Charging Energy.

Network Operating Agreement:

"Network Operating Agreement" shall mean an executed agreement that contains the terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Network Integration Transmission Service under Tariff, Part III.

Network Operating Committee:

"Network Operating Committee" shall mean a group made up of representatives from the Network Customer(s) and the Transmission Provider established to coordinate operating criteria and other technical considerations required for implementation of Network Integration Transmission Service under Tariff, Part III.

Network Resource:

"Network Resource" shall mean any designated generating resource owned, purchased, or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis, except for purposes of fulfilling obligations under a reserve sharing program.

Network Service User:

"Network Service User" shall mean an entity using Network Transmission Service.

Network Transmission Service:

"Network Transmission Service" shall mean transmission service provided pursuant to the rates, terms and conditions set forth in Tariff, Part III, or transmission service comparable to such service that is provided to a Load Serving Entity that is also a Transmission Owner.

Network Upgrades:

"Network Upgrades" shall mean modifications or additions to transmission-related facilities that are integrated with and support the Transmission Provider's overall Transmission System for the general benefit of all users of such Transmission System. Network Upgrades shall include:

(i) **Direct Connection Network Upgrades** which are Network Upgrades that are not part of an Affected System; only serve the Customer Interconnection Facility; and have no impact or potential impact on the Transmission System until the final tie-in is complete. Both Transmission Provider and Interconnection Customer must agree as to what constitutes Direct Connection Network Upgrades and identify them in the Interconnection Construction Service Agreement, Schedule D. If the Transmission Provider and Interconnection Customer disagree about whether a particular Network Upgrade is a Direct Connection Network Upgrade, the Transmission Provider must provide the Interconnection Customer a written technical explanation outlining why the Transmission Provider does not consider the Network Upgrade to be a Direcct Connection Network Upgrade within 15 days of its determination.

(ii) **Non-Direct Connection Network Upgrades** which are parallel flow Network Upgrades that are not Direct Connection Network Upgrades.

Neutral Party:

"Neutral Party" shall have the meaning provided in Tariff, Part I, section 9.3(v).

New Entry Capacity Resource:

"New Entry Capacity Resource" shall mean (1) a Capacity Resource with State Subsidy or (2) a natural gas-fired combined cycle resource or combustion turbine resource, that has not cleared in an RPM Auction pursuant to its Sell Offer at or above its resource-specific MOPR Floor Offer Price or the applicable default New Entry MOPR Floor Offer Price. Notwithstanding the foregoing, any Capacity Resource that previously cleared an RPM Auction before it became entitled to receive a State Subsidy shall not be deemed a New Entry Capacity Resource.

New PJM Zone(s):

"New PJM Zone(s)" shall mean the Zone included in the Tariff, along with applicable Schedules and Attachments, for Commonwealth Edison Company, The Dayton Power and Light Company and the AEP East Operating Companies (Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company).

New Service Customers:

"New Service Customers" shall mean all customers that submit an Interconnection Request, a Completed Application, or an Upgrade Request that is pending in the New Services Queue.

New Service Request:

"New Service Request" shall mean an Interconnection Request, a Completed Application, or an Upgrade Request.

New Services Queue:

"New Service Queue" shall mean all Interconnection Requests, Completed Applications, and Upgrade Requests that are received within each six-month period ending on April 30 and October 31 of each year shall collectively comprise a New Services Queue.

New Services Queue Closing Date:

"New Services Queue Closing Date" shall mean each April 30 and October 31 shall be the Queue Closing Date for the New Services Queue comprised of Interconnection Requests, Completed Applications, and Upgrade Requests received during the six-month period ending on such date.

New York ISO or NYISO:

"New York ISO" or "NYISO" shall mean the New York Independent System Operator, Inc. or any successor thereto.

Nodal Reference Price:

The "Nodal Reference Price" at each location shall mean the 97th percentile price differential between day-ahead and real-time prices experienced over the corresponding two-month reference period in the prior calendar year. Reference periods will be Jan-Feb, Mar-Apr, May-Jun, Jul-Aug, Sept-Oct, Nov-Dec. For any given current-year month, the reference period months will be the set of two months in the prior calendar year that include the month corresponding to the current month. For example, July and August 2003 would each use July-August 2002 as their reference period.

No-load Cost:

"No-load Cost" shall mean the hourly cost required to create the starting point of a monotonically increasing incremental offer curve for a generating unit.

Nominal Rated Capability:

"Nominal Rated Capability" shall mean the nominal maximum rated capability in megawatts of a Transmission Interconnection Customer's Customer Facility or the nominal increase in transmission capability in megawatts of the Transmission System resulting from the interconnection or addition of a Transmission Interconnection Customer's Customer Facility, as determined in accordance with pertinent Applicable Standards and specified in the Interconnection Service Agreement.

Nominated Demand Resource Value:

"Nominated Demand Resource Value" shall mean the amount of load reduction that a Demand Resource commits to provide either through direct load control, firm service level or guaranteed load drop programs. For existing Demand Resources, the maximum Nominated Demand Resource Value is limited, in accordance with the PJM Manuals, to the value appropriate for the method by which the load reduction would be accomplished, at the time the Base Residual Auction or Incremental Auction is being conducted.

Nominated Energy Efficiency Value:

"Nominated Energy Efficiency Value" shall mean the amount of load reduction that an Energy Efficiency Resource commits to provide through installation of more efficient devices or equipment or implementation of more efficient processes or systems.

Non-Dispatched Charging Energy:

"Non-Dispatched Charging Energy" shall mean all Direct Charging Energy that an Energy Storage Resource Model Participant receives from the electric grid that is not otherwise Dispatched Charging Energy.

Non-Firm Point-To-Point Transmission Service:

"Non-Firm Point-To-Point Transmission Service" shall mean Point-To-Point Transmission Service under the Tariff that is reserved and scheduled on an as-available basis and is subject to Curtailment or Interruption as set forth in Tariff, Part II, section 14.7. Non-Firm Point-To-Point Transmission Service is available on a stand-alone basis for periods ranging from one hour to one month.

Non-Firm Sale:

"Non-Firm Sale" shall mean an energy sale for which receipt or delivery may be interrupted for any reason or no reason, without liability on the part of either the buyer or seller.

Non-Firm Transmission Withdrawal Rights:

"No-Firm Transmission Withdrawal Rights" shall mean the rights to schedule energy withdrawals from a specified point on the Transmission System. Non-Firm Transmission Withdrawal Rights may be awarded only to a Merchant D.C. Transmission Facility that connects the Transmission System to another control area. Withdrawals scheduled using Non-Firm Transmission Withdrawal Rights have rights similar to those under Non-Firm Point-to-Point Transmission Service.

Non-Performance Charge:

“Non-Performance Charge” shall mean the charge applicable to Capacity Performance Resources as defined in Tariff, Attachment DD, section 10A(e).

Nonincumbent Developer:

“Nonincumbent Developer” shall have the same meaning provided in the Operating Agreement.

Non-Regulatory Opportunity Cost:

“Non-Regulatory Opportunity Cost” shall mean the difference between (a) the forecasted cost to operate a specific generating unit when the unit only has a limited number of starts or available run hours resulting from (i) the physical equipment limitations of the unit, for up to one year, due to original equipment manufacturer recommendations or insurance carrier restrictions, (ii) a fuel supply limitation, for up to one year, resulting from an event of Catastrophic Force Majeure; and, (b) the forecasted future Locational Marginal Price at which the generating unit could run while not violating such limitations. Non-Regulatory Opportunity Cost therefore is the value associated with a specific generating unit’s lost opportunity to produce energy during a higher valued period of time occurring within the same period of time in which the unit is bound by the referenced restrictions, and is reflected in the rules set forth in PJM Manual 15. Non-Regulatory Opportunity Costs shall be limited to those resources which are specifically delineated in Operating Agreement, Schedule 2.

Non-Retail Behind The Meter Generation:

“Non-Retail Behind The Meter Generation” shall mean Behind the Meter Generation that is used by municipal electric systems, electric cooperatives, or electric distribution companies to serve load.

Non-Synchronized Reserve:

“Non-Synchronized Reserve” shall mean the reserve capability of non-emergency generation resources that can be converted fully into energy within ten minutes of a request from the Office of the Interconnection dispatcher, and is provided by equipment that is not electrically synchronized to the Transmission System.

Non-Synchronized Reserve Event:

“Non-Synchronized Reserve Event” shall mean a request from the Office of the Interconnection to generation resources able and assigned to provide Non-Synchronized Reserve in one or more specified Reserve Zones or Reserve Sub-zones, within ten minutes to increase the energy output by the amount of assigned Non-Synchronized Reserve capability.

Non-Variable Loads:

“Non-Variable Loads” shall have the meaning specified in Operating Agreement, Schedule 1, section 1.5A.6, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.5A.6.

Non-Zone Network Load:

“Non-Zone Network Load shall mean Network Load that is located outside of the PJM Region.

Normal Maximum Generation:

“Normal Maximum Generation” shall mean the highest output level of a generating resource under normal operating conditions.

Normal Minimum Generation:

“Normal Minimum Generation” shall mean the lowest output level of a generating resource under normal operating conditions.

Definitions – R - S

Ramping Capability:

"Ramping Capability" shall mean the sustained rate of change of generator output, in megawatts per minute.

Real-time Congestion Price:

"Real-time Congestion Price" shall mean the Congestion Price resulting from the Office of the Interconnection's dispatch of the PJM Interchange Energy Market in the Operating Day.

Real-time Loss Price:

"Real-time Loss Price" shall mean the Loss Price resulting from the Office of the Interconnection's dispatch of the PJM Interchange Energy Market in the Operating Day.

Real-time Energy Market:

"Real-time Energy Market" shall mean the purchase or sale of energy and payment of Transmission Congestion Charges for quantity deviations from the Day-ahead Energy Market in the Operating Day.

Real-time Offer:

"Real-time Offer" shall mean a new offer or an update to a Market Seller's existing cost-based or market-based offer for a clock hour, submitted for use after the close of the Day-ahead Energy Market.

Real-time Prices:

"Real-time Prices" shall mean the Locational Marginal Prices resulting from the Office of the Interconnection's dispatch of the PJM Interchange Energy Market in the Operating Day.

Real-time Settlement Interval:

"Real-time Settlement Interval" shall mean the interval used by settlements, which shall be every five minutes.

Real-time System Energy Price:

"Real-time System Energy Price" shall mean the System Energy Price resulting from the Office of the Interconnection's dispatch of the PJM Interchange Energy Market in the Operating Day.

Reasonable Efforts:

"Reasonable Efforts" shall mean, with respect to any action required to be made, attempted, or taken by an Interconnection Party or by a Construction Party under Tariff, Part IV or Part VI, an Interconnection Service Agreement, or a Construction Service Agreement, such efforts as are timely and consistent with Good Utility Practice and with efforts that such party would undertake for the protection of its own interests.

Receiving Party:

"Receiving Party" shall mean the entity receiving the capacity and energy transmitted by the Transmission Provider to Point(s) of Delivery.

Referral:

"Referral" shall mean a formal report of the Market Monitoring Unit to the Commission for investigation of behavior of a Market Participant, of behavior of PJM, or of a market design flaw, pursuant to Tariff, Attachment M, section IV.I.

Reference Resource:

"Reference Resource" shall mean a combustion turbine generating station, configured with a single General Electric Frame 7HA turbine with evaporative cooling, Selective Catalytic Reduction technology all CONE Areas, dual fuel capability, and a heat rate of 9.134 Mmbtu/MWh.

Regional Entity:

"Regional Entity" shall have the same meaning specified in the Operating Agreement.

Regional Transmission Expansion Plan:

"Regional Transmission Expansion Plan" shall mean the plan prepared by the Office of the Interconnection pursuant to Operating Agreement, Schedule 6 for the enhancement and expansion of the Transmission System in order to meet the demands for firm transmission service in the PJM Region.

Regional Transmission Group (RTG):

"Regional Transmission Group" or "RTG" shall mean a voluntary organization of transmission owners, transmission users and other entities approved by the Commission to efficiently coordinate transmission planning (and expansion), operation and use on a regional (and interregional) basis.

Regulation:

"Regulation" shall mean the capability of a specific generation resource or Demand Resource with appropriate telecommunications, control and response capability to separately increase and decrease its output or adjust load in response to a regulating control signal, in accordance with the specifications in the PJM Manuals.

Regulation Zone:

"Regulation Zone" shall mean any of those one or more geographic areas, each consisting of a combination of one or more Control Zone(s) as designated by the Office of the Interconnection in the PJM Manuals, relevant to provision of, and requirements for, regulation service.

Relevant Electric Retail Regulatory Authority:

"Relevant Electric Retail Regulatory Authority" shall mean an entity that has jurisdiction over and establishes prices and policies for competition for providers of retail electric service to end-customers, such as the city council for a municipal utility, the governing board of a cooperative utility, the state public utility commission or any other such entity.

Reliability Assurance Agreement or PJM Reliability Assurance Agreement:

"Reliability Assurance Agreement" or "PJM Reliability Assurance Agreement" shall mean that certain Reliability Assurance Agreement Among Load Serving Entities in the PJM Region, on file with FERC as PJM Interconnection L.L.C. Rate Schedule FERC No. 44, and as amended from time to time thereafter.

Reliability Pricing Model Auction:

"Reliability Pricing Model Auction" or "RPM Auction" shall mean the Base Residual Auction or any Incremental Auction, or, for the 2016/2017 and 2017/2018 Delivery Years, any Capacity Performance Transition Incremental Auction.

Required Transmission Enhancements:

"Regional Transmission Enhancements" shall mean enhancements and expansions of the Transmission System that (1) a Regional Transmission Expansion Plan developed pursuant to Operating Agreement, Schedule 6 or (2) any joint planning or coordination agreement between PJM and another region or transmission planning authority set forth in Tariff, Schedule 12-Appendix B ("Appendix B Agreement") designates one or more of the Transmission Owner(s) to construct and own or finance. Required Transmission Enhancements shall also include enhancements and expansions of facilities in another region or planning authority that meet the definition of transmission facilities pursuant to FERC's Uniform System of Accounts or have been classified as transmission facilities in a ruling by FERC addressing such facilities constructed pursuant to an Appendix B Agreement cost responsibility for which has been assigned at least in part to PJM pursuant to such Appendix B Agreement.

Reserved Capacity:

"Reserved Capacity" shall mean the maximum amount of capacity and energy that the Transmission Provider agrees to transmit for the Transmission Customer over the Transmission Provider's Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Tariff, Part II. Reserved Capacity shall be expressed in terms of whole megawatts on a sixty (60) minute interval (commencing on the clock hour) basis.

Reserve Penalty Factor:

"Reserve Penalty Factor" shall mean the cost, in $/MWh, associated with being unable to meet a specific reserve requirement in a Reserve Zone or Reserve Sub-zone. A Reserve Penalty Factor will be defined for each reserve requirement in a Reserve Zone or Reserve Sub-zone.

Reserve Sub-zone:

"Reserve Sub-zone" shall mean any of those geographic areas wholly contained within a Reserve Zone, consisting of a combination of a portion of one or more Control Zone(s) as designated by the Office of the Interconnection in the PJM Manuals, relevant to provision of, and requirements for, reserve service.

Reserve Zone:

"Reserve Zone" shall mean any of those geographic areas consisting of a combination of one or more Control Zone(s), as designated by the Office of the Interconnection in the PJM Manuals, relevant to provision of, and requirements for, reserve service.

Residual Auction Revenue Rights:

"Residual Auction Revenue Rights" shall mean incremental stage 1 Auction Revenue Rights created within a Planning Period by an increase in transmission system capability, including the return to service of existing transmission capability, that was not modeled pursuant to Operating Agreement, Schedule 1, section 7.5 and the parallel provisions of Tariff, Attachment K-Appendix, section 7.5 in compliance with Operating Agreement, Schedule 1, section 7.4.2 (h) and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.2(h), and, if modeled, would have increased the amount of stage 1 Auction Revenue Rights allocated pursuant to Operating Agreement, Schedule 1, section 7.4.2 and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.2; provided that, the foregoing notwithstanding, Residual Auction Revenue Rights shall exclude: 1) Incremental Auction Revenue Rights allocated pursuant to Tariff, Part VI; and 2) Auction Revenue Rights allocated to entities that are assigned cost responsibility pursuant to Operating Agreement, Schedule 6 for transmission upgrades that create such rights.

Residual Metered Load:

"Residual Metered Load" shall mean all load remaining in an electric distribution company's fully metered franchise area(s) or service territory(ies) after all nodally priced load of entities serving load in such area(s) or territory(ies) has been carved out.

Resource Substitution Charge:

"Resource Substitution Charge" shall mean a charge assessed on Capacity Market Buyers in an Incremental Auction to recover the cost of replacement Capacity Resources.

Revenue Data for Settlements:

"Revenue Data for Settlements" shall mean energy quantities used in accounting and billing as determined pursuant to Tariff, Attachment K-Appendix and the corresponding provisions of Operating Agreement, Schedule 1.

RPM Seller Credit:

"RPM Seller Credit" shall mean an additional form of Unsecured Credit defined in Tariff, Attachment Q, section IV.

Scheduled Incremental Auctions:

"Scheduled Incremental Auctions" shall refer to the First, Second, or Third Incremental Auction.

Schedule of Work:

"Schedule of Work" shall mean that schedule attached to the Interconnection Construction Service Agreement setting forth the timing of work to be performed by the Constructing Entity pursuant to the Interconnection Construction Service Agreement, based upon the Facilities Study and subject to modification, as required, in accordance with Transmission Provider's scope change process for interconnection projects set forth in the PJM Manuals.

Scope of Work:

"Scope of Work" shall mean that scope of the work attached as a schedule to the Interconnection Construction Service Agreement and to be performed by the Constructing Entity(ies) pursuant to the Interconnection Construction Service Agreement, provided that such Scope of Work may be modified, as required, in accordance with Transmission Provider's scope change process for interconnection projects set forth in the PJM Manuals.

Seasonal Capacity Performance Resource:

"Seasonal Capacity Performance Resource" shall have the same meaning specified in Tariff, Attachment DD, section 5.5A.

Secondary Systems:

"Secondary Systems" shall mean control or power circuits that operate below 600 volts, AC or DC, including, but not limited to, any hardware, control or protective devices, cables, conductors, electric raceways, secondary equipment panels, transducers, batteries, chargers, and voltage and current transformers.

Second Incremental Auction:

"Second Incremental Auction" shall mean an Incremental Auction conducted ten months before the Delivery Year to which it relates**.**

Security:

"Security" shall mean the security provided by the New Service Customer pursuant to Tariff, section 212.4 or Tariff, Part VI, section 213.4 to secure the New Service Customer's responsibility for Costs under the Interconnection Service Agreement or Upgrade Construction Service Agreement and Tariff, Part VI, section 217.

Segment:
"Segment" shall have the same meaning as described in Operating Agreement, Schedule 1, section 3.2.3(e).

Self-Supply:

"Self-Supply" shall mean Capacity Resources secured by a Load-Serving Entity, by ownership or contract, outside a Reliability Pricing Model Auction, and used to meet obligations under this Attachment or the Reliability Assurance Agreement through submission in a Base Residual Auction or an Incremental Auction of a Sell Offer indicating such Market Seller's intent that such Capacity Resource be Self-Supply. Self-Supply may be either committed regardless of clearing price or submitted as a Sell Offer with a price bid. A Load Serving Entity's Sell Offer with a price bid for an owned or contracted Capacity Resource shall not be deemed "Self-Supply," unless it is designated as Self-Supply and used by the LSE to meet obligations under this Attachment or the Reliability Assurance Agreement.

Self-Supply Entity:

"Self-Supply Entity" shall mean the following types of Load Serving Entity that operate under long-standing business models: single customer entity, public power entity, or vertically integrated utility, where "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 or receives any cost recovery for such generation through bilateral contracts; "single customer entity" means a Load Serving Entity that serves at retail only customers that are under common control with such Load Serving Entity, where such control means holding 51% or more of the voting securities or voting interests of the Load Serving Entity and all its retail customers; and "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.

Sell Offer:

“Sell Offer” shall mean an offer to sell Capacity Resources in a Base Residual Auction, Incremental Auction, or Reliability Backstop Auction.

Service Agreement:

“Service Agreement” shall mean the initial agreement and any amendments or supplements thereto entered into by the Transmission Customer and the Transmission Provider for service under the Tariff.

Service Commencement Date:

“Service Commencement Date” shall mean the date the Transmission Provider begins to provide service pursuant to the terms of an executed Service Agreement, or the date the Transmission Provider begins to provide service in accordance with Tariff, Part II, section 15.3 or Tariff, Part III, section 29.1.

Short-Term Firm Point-To-Point Transmission Service:

“Short-Term Firm Point-To-Point Transmission Service” shall mean Firm Point-To-Point Transmission Service under Tariff, Part II with a term of less than one year.

Short-term Project:

“Short-term Project” shall have the same meaning provided in the Operating Agreement.

Short-Term Resource Procurement Target:

“Short-Term Resource Procurement Target” shall mean, for Delivery Years through May 31, 2018, as to the PJM Region, for purposes of the Base Residual Auction, 2.5% of the PJM Region Reliability Requirement determined for such Base Residual Auction, for purposes of the First Incremental Auction, 2% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction; and, for purposes of the Second Incremental Auction, 1.5% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction; and, as to any Zone, an allocation of the PJM Region Short-Term Resource Procurement Target based on the Preliminary Zonal Forecast Peak Load, reduced by the amount of load served under the FRR Alternative. For any LDA, the LDA Short-Term Resource Procurement Target shall be the sum of the Short-Term Resource Procurement Targets of all Zones in the LDA.

Short-Term Resource Procurement Target Applicable Share:

“Short-Term Resource Procurement Target Applicable Share” shall mean, for Delivery Years through May 31, 2018: (i) for the PJM Region, as to the First and Second Incremental Auctions, 0.2 times the Short-Term Resource Procurement Target used in the Base Residual Auction and, as to the Third Incremental Auction for the PJM Region, 0.6 times such target; and (ii) for an

LDA, as to the First and Second Incremental Auctions, 0.2 times the Short-Term Resource Procurement Target used in the Base Residual Auction for such LDA and, as to the Third Incremental Auction, 0.6 times such target.

Site:

"Site" shall mean all of the real property, including but not limited to any leased real property and easements, on which the Customer Facility is situated and/or on which the Customer Interconnection Facilities are to be located.

Small Commercial Customer:

"Small Commercial Customer," as used in RAA, Schedule 6 and Tariff, Attachment DD-1, shall mean a commercial retail electric end-use customer of an electric distribution company that participates in a mass market demand response program under the jurisdiction of a RERRA and satisfies the definition of a "small commercial customer" under the terms of the applicable RERRA's program, provided that the customer has an annual peak demand no greater than 100kW.

Small Generation Resource:

"Small Generation Resource" shall mean an Interconnection Customer's device of 20 MW or less for the production and/or storage for later injection of electricity identified in an Interconnection Request, but shall not include the Interconnection Customer's Interconnection Facilities. This term shall include Energy Storage Resources and/or other devices for storage for later injection of energy.

Small Inverter Facility:

"Small Inverter Facility" shall mean an Energy Resource that is a certified small inverter-based facility no larger than 10 kW.

Small Inverter ISA:

"Small Inverter ISA" shall mean an agreement among Transmission Provider, Interconnection Customer, and Interconnected Transmission Owner regarding interconnection of a Small Inverter Facility under Tariff, Part IV, section 112B.

Special Member:

"Special Member" shall mean an entity that satisfies the requirements of Operating Agreement, Schedule 1, section 1.5A.02, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.5A.02, or the special membership provisions established under the Emergency Load Response and Pre-Emergency Load Response Programs.

Spot Market Backup:

"Spot Market Backup" shall mean the purchase of energy from, or the delivery of energy to, the PJM Interchange Energy Market in quantities sufficient to complete the delivery or receipt obligations of a bilateral contract that has been curtailed or interrupted for any reason.

Spot Market Energy:

"Spot Market Energy" shall mean energy bought or sold by Market Participants through the PJM Interchange Energy Market at System Energy Prices determined as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

Start Additional Labor Costs:

"Start Additional Labor Costs" shall mean additional labor costs for startup required above normal station manning levels.

Start-Up Costs:

"Start-Up Costs" shall mean the unit costs to bring the boiler, turbine and generator from shutdown conditions to the point after breaker closure which is typically indicated by telemetered or aggregated state estimator megawatts greater than zero and is determined based on the cost of start fuel, total fuel-related cost, performance factor, electrical costs (station service), start maintenance adder, and additional labor cost if required above normal station manning. Start-Up Costs can vary with the unit offline time being categorized in three unit temperature conditions: hot, intermediate and cold.

State:

"State" shall mean the District of Columbia and any State or Commonwealth of the United States.

State Commission:

"State Commission**"** shall mean any state regulatory agency having jurisdiction over retail electricity sales in any State in the PJM Region.

State Estimator:

"State Estimator" shall mean the computer model of power flows specified in Operating Agreement, Schedule 1, section 2.3 and the parallel provisions of Tariff, Attachment K-Appendix, section 2.3.

State Subsidy:

“State Subsidy” shall mean a direct or indirect payment, concession, rebate, subsidy, non-bypassable consumer charge, or other financial benefit that is as a result of any action, mandated process, or sponsored process of a state government, a political subdivision or agency of a state, or an electric cooperative formed pursuant to state law, and that

(1) is derived from or connected to the procurement of (a) electricity or electric generation capacity sold at wholesale in interstate commerce, or (b) an attribute of the generation process for electricity or electric generation capacity sold at wholesale in interstate commerce; or

(2) will support the construction, development, or operation of a new or existing Capacity Resource; or

(3) could have the effect of allowing the unit to clear in any PJM capacity auction.

Notwithstanding the foregoing, State Subsidy shall not include (a) payments, 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 designed to incent siting facilities in that county or locality rather than another county or locality; (b) state action that imposes a tax or assesses a charge utilizing the parameters of a regional program on a given set of resources notwithstanding the tax or cost having indirect benefits on resources not subject to the tax or cost (e.g., Regional Greenhouse Gas Initiative); (c) any indirect benefits to a Capacity Resource as a result of any transmission project approved as part of the Regional Transmission Expansion Plan; (d) any contract, legally enforceable obligation, or rate pursuant to the Public Utility Regulatory Policies Act or any other state-administered federal regulatory program (e.g., the Cross-State Air Pollution Rule); (e) any state-directed default service procurement program that is competitively procured without regard to resource fuel type (e.g., New Jersey Basic Generation Service, Maryland Standard Offer Service); (f) any revenues for providing capacity as part of an FRR Capacity Plan or through bilateral transactions with FRR Entities; or (g) any voluntary and arm’s length bilateral transaction (including but not limited to those reported pursuant to Tariff, Attachment DD, section 4.6), such as a power purchase agreement or other similar contract where the buyer is a Self-Supply Entity and the transaction is (1) a short term transaction (one-year or less) or (2) a long-term transaction that is the result of a competitive process that was not fuel-specific and is not used for the purpose of supporting uneconomic construction, development, or operation of the subject Capacity Resource, provided however that if the Self-Supply Entity is responsible for offering the Capacity Resource into an RPM Auction, the specified amount of installed capacity purchased by such Self-Supply Entity shall be considered to receive a State Subsidy in the same manner, under the same conditions, and to the same extent as any other Capacity Resource of a Self-Supply Entity.

State of Charge:

“State of Charge” shall mean the quantity of physical energy stored in an Energy Storage Resource Model Participant in proportion to its maximum State of Charge capability. State of Charge is quantified as defined in the PJM Manuals.

State of Charge Management:

"State of Charge Management" shall mean the control of State of Charge of an Energy Storage Resource Market Participant using minimum and maximum charge and discharge limits, changes in operating mode, charging and discharging offer curves, and self-scheduling of non-dispatchable purchases and sales of energy in the PJM markets. State of Charge Management shall not interfere with an Energy Storage Resource Model Participant's obligation to follow PJM dispatch, consistent with all other resources.

Station Power:

"Station Power" shall mean energy used for operating the electric equipment on the site of a generation facility located in the PJM Region or for the heating, lighting, air-conditioning and office equipment needs of buildings on the site of such a generation facility that are used in the operation, maintenance, or repair of the facility. Station Power does not include any energy (i) used to power synchronous condensers; (ii) used for pumping at a pumped storage facility; (iii) used in association with restoration or black start service; or (iv) that is Direct Charging Energy.

Sub-Annual Resource Constraint:

"Sub-Annual Resource Constraint" shall mean, for the 2017/2018 Delivery Year and for FRR Capacity Plans the 2017/2018 and 2018/2019 Delivery Years, for the PJM Region or for each LDA for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for a Delivery Year, a limit on the total amount of Unforced Capacity that can be committed as Limited Demand Resources and Extended Summer Demand Resources for the 2017/2018 Delivery Year in the PJM Region or in such LDA, calculated as the Sub-Annual Resource Reliability Target for the PJM Region or for such LDA, respectively, minus the Short-Term Resource Procurement Target for the PJM Region or for such LDA, respectively.

Sub-Annual Resource Price Decrement:

"Sub-Annual Resource Price Decrement" shall mean, for the 2017/2018 Delivery Year, a difference between the clearing price for Extended Summer Demand Resources and the clearing price for Annual Resources, representing the cost to procure additional Annual Resources out of merit order when the Sub-Annual Resource Constraint is binding.

Sub-Annual Resource Reliability Target:

"Sub-Annual Reliability Target" for the PJM Region or an LDA, shall mean the maximum amount of the combination of Extended Summer Demand Resources and Limited Demand Resources in Unforced Capacity determined by PJM to be consistent with the maintenance of reliability, stated in Unforced Capacity, that shall be used to calculate the Minimum Annual Resource Requirement for Delivery Years through May 31, 2017 and the Sub-Annual Resource Constraint for the 2017/2018 and 2018/2019 Delivery Years. As more fully set forth in the PJM Manuals, PJM calculates the Sub-Annual Resource Reliability Target, by first determining a reference annual loss of load expectation ("LOLE") assuming no Demand Resources. The calculation for the unconstrained portion of the PJM Region uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast and iteratively shifting the load distributions to result in the Installed Reserve Margin established for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). The calculation for each relevant LDA uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Capacity Emergency Transfer Objective study for the Delivery Year in question). For the relevant LDA calculation, the weekly capacity distributions are adjusted to reflect the Capacity Emergency Transfer Limit for the Delivery Year in question.

For both the PJM Region and LDA analyses, PJM then models the commitment of varying amounts of DR (displacing otherwise committed generation) as interruptible from May 1 through October 31 and unavailable from November 1 through April 30 and calculates the LOLE at each DR level. The Extended Summer DR Reliability Target is the DR amount, stated as a percentage of the unrestricted peak load, that produces no more than a ten percent increase in the LOLE, compared to the reference value. The Sub-Annual Resource Reliability Target shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the DR Factor] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

Sub-meter:

"Sub-meter" shall mean a metering point for electricity consumption that does not include all electricity consumption for the end-use customer as defined by the electric distribution company account number. PJM shall only accept sub-meter load data from end-use customers for measurement and verification of Regulation service as set forth in the Economic Load Response rules and PJM Manuals.

Summer-Period Capacity Performance Resource:

"Summer-Period Capacity Performance Resource" shall have the same meaning specified in Tariff, Attachment DD, section 5.5A.

Surplus Interconnection Customer:

"Surplus Interconnection Customer" shall mean either an Interconnection Customer whose Generating Facility is already interconnected to the PJM Transmission System or one of its affiliates, or an unaffiliated entity that submits a Surplus Interconnection Request to utilize Surplus Interconnection Service within the Transmission System in the PJM Region. A Surplus Interconnection Customer is not a New Service Customer.

Surplus Interconnection Request:

"Surplus Interconnection Request" shall mean a request submitted by a Surplus Interconnection Customer, pursuant to Tariff, Attachment RR, to utilize Surplus Interconnection Service within the Transmission System in the PJM Region. A Surplus Interconnection Request is not a New Service Request.

Surplus Interconnection Service:

"Surplus Interconnection Service" shall mean any unneeded portion of Interconnection Service established in an Interconnection Service Agreement, such that if Surplus Interconnection Service is utilized, the total amount of Interconnection Service at the Point of Interconnection would remain the same.

Switching and Tagging Rules:

"Switching and Tagging Rules" shall mean the switching and tagging procedures of Interconnected Transmission Owners and Interconnection Customer as they may be amended from time to time.

Synchronized Reserve:

"Synchronized Reserve" shall mean the reserve capability of generation resources that can be converted fully into energy or Demand Resources whose demand can be reduced within ten minutes from the request of the Office of the Interconnection dispatcher, and is provided by equipment that is electrically synchronized to the Transmission System.

Synchronized Reserve Event:

"Synchronized Reserve Event" shall mean a request from the Office of the Interconnection to generation resources and/or Demand Resources able, assigned or self-scheduled to provide Synchronized Reserve in one or more specified Reserve Zones or Reserve Sub-zones, within ten minutes, to increase the energy output or reduce load by the amount of assigned or self-scheduled Synchronized Reserve capability.

Synchronized Reserve Requirement:

"Synchronized Reserve Requirement" shall mean the megawatts required to be maintained in a Reserve Zone or Reserve Sub-zone as Synchronized Reserve, absent any increase to account for additional reserves scheduled to address operational uncertainty. The Synchronized Reserve Requirement is calculated in accordance with the PJM Manuals.

System Condition:

"System Condition" shall mean a specified condition on the Transmission Provider's system or on a neighboring system, such as a constrained transmission element or flowgate, that may trigger Curtailment of Long-Term Firm Point-to-Point Transmission Service using the curtailment priority pursuant to Tariff, Part II, section 13.6. Such conditions must be identified in the Transmission Customer's Service Agreement.

System Energy Price:

"System Energy Price" shall mean the energy component of the Locational Marginal Price, which is the price at which the Market Seller has offered to supply an additional increment of energy from a resource, calculated as specified in Operating Agreement, Schedule 1, section 2 and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

System Impact Study:

"System Impact Study" shall mean an assessment by the Transmission Provider of (i) the adequacy of the Transmission System to accommodate a Completed Application, an Interconnection Request or an Upgrade Request, (ii) whether any additional costs may be incurred in order to provide such transmission service or to accommodate an Interconnection Request, and (iii) with respect to an Interconnection Request, an estimated date that an Interconnection Customer's Customer Facility can be interconnected with the Transmission System and an estimate of the Interconnection Customer's cost responsibility for the interconnection; and (iv) with respect to an Upgrade Request, the estimated cost of the requested system upgrades or expansion, or of the cost of the system upgrades or expansion, necessary to provide the requested incremental rights.

System Protection Facilities:

"System Protection Facilities" shall refer to the equipment required to protect (i) the Transmission System, other delivery systems and/or other generating systems connected to the Transmission System from faults or other electrical disturbance occurring at or on the Customer Facility, and (ii) the Customer Facility from faults or other electrical system disturbance occurring on the Transmission System or on other delivery systems and/or other generating systems to which the Transmission System is directly or indirectly connected. System Protection Facilities shall include such protective and regulating devices as are identified in the Applicable Technical Requirements and Standards or that are required by Applicable Laws and Regulations or other Applicable Standards, or as are otherwise necessary to protect personnel and equipment and to minimize deleterious effects to the Transmission System arising from the Customer Facility.

5.6 Sell Offers

Sell Offers shall be submitted or withdrawn via the internet site designated by the Office of the Interconnection, under the procedures and time schedule set forth in the PJM Manuals.

5.6.1 Specifications

A Sell Offer shall state quantities in increments of 0.1 megawatts and shall specify, as appropriate:

a) Identification of the Generation Capacity Resource, Demand Resource, Capacity Storage Resource or Energy Efficiency Resource on which such Sell Offer is based;

b) Minimum and maximum megawatt quantity of installed capacity that the Capacity Market Seller is willing to offer (notwithstanding such specification, the product offered shall be Unforced Capacity), or designate as Self-Supply, from a Generation Capacity Resource;

i) Price, in dollars and cents per megawatt-day, that will be accepted by the Capacity Market Seller for the megawatt quantity of Unforced Capacity offered from such Generation Capacity Resource.

ii) The Sell Offer may take the form of offer segments with varying price-quantity pairs for varying output levels from the underlying resource, but may not take the form of an offer curve with nonzero slope.

c) EFORd of each Generation Capacity Resource offered.

i) If a Capacity Market Seller is offering such resource in a Base Residual Auction, First Incremental Auction, Second Incremental Auction, or Conditional Incremental Auction occurring before the Third Incremental Auction, the Capacity Market Seller shall specify the EFORd to apply to the offer.

ii) If a Capacity Market Seller is committing the resource as Self-Supply, the Capacity Market Seller shall specify the EFORd to apply to the commitment.

iii) The EFORd applied to the Third Incremental Auction will be the final EFORd established by the Office of the Interconnection six (6) months prior to the Delivery Year, based on the actual EFORd in the PJM Region during the 12-month period ending September 30 that last precedes such Delivery Year.

d) The Nominated Demand Resource Value for each Demand Resource offered and the Nominated Energy Efficiency Value for each Energy Efficiency Resource offered. The Office of the Interconnection shall, in both cases, convert such value to an Unforced Capacity basis by multiplying such value by the DR Factor (for Delivery Years through May 31, 2018) times the Forecast Pool Requirement. Demand Resources shall specify the LDA in which the Demand Resource is located, including the location of such resource within any Zone that includes more than one LDA as identified on Schedule 10.1 of the RAA.

e) For Delivery Years through May 31, 2018, a Demand Resource with the potential to qualify as two or more of a Limited Demand Resource, Extended Summer Demand Resource or Annual Demand Resource may submit separate but coupled Sell Offers for each Demand Resource type for which it qualifies at different prices and the auction clearing algorithm will select the Sell Offer that yields the least-cost solution. For such coupled Demand Resource offers, the offer price of an Annual Demand Resource offer must be at least $.01 per MW-day greater than the offer price of a coupled Extended Summer Demand Resource offer and the offer price of a Extended Summer Demand Resource offer must be at least $.01 per MW-day greater than the offer price of a coupled Limited Demand Resource offer.

f) For a Qualifying Transmission Upgrade, the Sell Offer shall identify such upgrade, and the Office of the Interconnection shall determine and certify the increase in CETL provided by such upgrade. The Capacity Market Seller may offer the upgrade with an associated increase in CETL to an LDA in accordance with such certification, including an offer price that will be accepted by the Capacity Market Seller, stated in dollars and cents per megawatt-day as a price difference between a Capacity Resource located outside such an LDA and a Capacity Resource located inside such LDA; and the increase in CETL into such LDA to be provided by such Qualifying Transmission Upgrade, as certified by the Office of the Interconnection.

g) For the 2018/2019 and 2019/2020 Delivery Years, each Capacity Market Seller owning or controlling a resource that qualifies as both a Base Capacity Resource and a Capacity Performance Resource may submit separate but coupled Sell Offers for such resource as a Base Capacity Resource and as a Capacity Performance Resource, at different prices, and the auction clearing algorithm will select the Sell Offer that yields the least-cost solution. Submission of a coupled Base Capacity Resource Sell Offer shall be mandatory for any Capacity Performance Resource Sell Offer that exceeds a Sell Offer Price equal to the applicable Net Cost of New Entry times the Balancing Ratio as provided for in section 6.4. For such coupled Sell Offers, the offer price of a Capacity Performance Resource offer must be at least $.01 per MW-day greater than the offer price of a coupled Base Capacity Resource offer.

(h) For the 2018/2019 Delivery Year and subsequent Delivery Years, a Capacity Market Seller that owns or controls one or more Capacity Storage Resources, Intermittent Resources, Demand Resources, or Energy Efficiency Resources may submit a Sell Offer as a Capacity Performance Resource in a MW quantity consistent with their average expected output during peak-hour periods. Alternatively, for the 2018/2019 Delivery Year and subsequent Delivery Years, a Capacity Market Seller that owns or controls one or more Capacity Storage Resources, Intermittent Resources, Demand Resources, Energy Efficiency Resources, or Environmentally-Limited Resources may submit a Sell Offer which represents the aggregated Unforced Capacity value of such resources, where such Sell Offer shall be considered to be located in the smallest modeled LDA common to the aggregated resources. Such aggregated resources shall be owned by or under contract to the Capacity Market Seller, including all such resources obtained through bilateral contract and reported to the Office of the Interconnection in accordance with the Office of the Interconnection's rules related to its ~~eRPM~~ Capacity Exchange tools. If any of the commercially aggregated resources in such Sell Offer are subject to the Minimum Floor Offer Price pursuant to Tariff, Attachment DD, section 5.14(h), the Capacity Market Seller that owns or controls such resources may submit a Sell Offer with a Minimum

Floor Offer Price of no lower than the time and MW-weighted average of the applicable MOPR Floor Offer Prices (zero if not applicable) of the aggregated resources in such Sell Offer.~~For the 2018/2019 and 2019/2020 Delivery Years, any such offer may be submitted as Capacity Performance Resource, Base Capacity Resource, or as a coupled offer for Capacity Performance Resource and Base Capacity Resource, provided that, for any such coupled Sell Offers, the offer price of a Capacity Performance Resource offer must be at least $.01 per MW-day greater than the offer price of a coupled Base Capacity Resource offer. For the 2020/2021 Delivery Year and subsequent Delivery Years, any such offer must be submitted as a Capacity Performance Resource.~~

(i) For the 2020/2021 Delivery Year and subsequent Delivery Years, a Capacity Market Seller that owns or controls a resource that qualifies as a Summer-Period Capacity Performance Resource may submit a Sell Offer as a Capacity Performance Resource in a MW quantity consistent with the average expected output of such resource during peak-hour periods, and may submit a separate Sell Offer as a Summer-Period Capacity Performance Resource in a MW quantity consistent with the average expected output of such resource during summer peak-hour periods, provided the total Sell Offer MW quantity submitted as both a Capacity Performance Resource and a Summer-Period Capacity Performance Resource does not exceed the Unforced Capacity value of the resource. For the 2020/2021 Delivery Year and subsequent Delivery Years, a Capacity Market Seller that owns or controls a resource that qualifies as a Winter-Period Capacity Performance Resource may submit a Sell Offer as a Capacity Performance Resource in a MW quantity consistent with the average expected output of such resource during peak-hour periods, and may submit a separate Sell Offer as a Winter-Period Capacity Performance Resource in a MW quantity consistent with the average expected output of such resource during winter peak-hour periods, provided the total Sell Offer MW quantity submitted as both a Capacity Performance Resource and a Winter-Period Capacity Performance Resource does not exceed the Unforced Capacity value of the resource. Each segment of a Seasonal Capacity Performance Resource Sell Offer must be submitted as a flexible Sell Offer segment with the minimum MW quantity offered set to zero.

5.6.2 Compliance with PJM Credit Policy

Capacity Market Sellers shall comply with the provisions of the PJM Credit Policy as set forth in Attachment Q to this Tariff, including the provisions specific to the Reliability Pricing Model, prior to submission of Sell Offers in any Reliability Pricing Model Auction. A Capacity Market Seller desiring to submit a Credit-Limited Offer shall specify in its Sell Offer the maximum auction credit requirement, in dollars, and the maximum amount of Unforced Capacity, in megawatts, applicable to its Sell Offer.

5.6.3 [reserved]

5.6.4 Qualifying Transmission Upgrades

A Qualifying Transmission Upgrade may not be the subject of any Sell Offer in a Base Residual Auction unless it has been approved by the Office of the Interconnection, including certification of the increase in Import Capability to be provided by such Qualifying Transmission Upgrade, no later than 45 days prior to such Base Residual Auction. No such approval shall be granted unless, at a minimum, a Facilities Study Agreement has been executed with respect to such upgrade, and such upgrade conforms to all applicable standards of the Regional Transmission Expansion Plan process.

5.6.5 Market-based Sell Offers

Subject to section 6, a Market Seller authorized by FERC to sell electric generating capacity at market-based prices, or that is not required to have such authorization, may submit Sell Offers that specify market-based prices in any Base Residual Auction or Incremental Auction.

5.6.6 Availability of Capacity Resources for Sale

(a) The Office of the Interconnection shall determine the quantity of megawatts of available installed capacity that each Capacity Market Seller must offer in any RPM Auction pursuant to Section 6.6 of Attachment DD, through verification of the availability of megawatts of installed capacity from: (i) all Generation Capacity Resources owned by or under contract to the Capacity Market Seller, including all Generation Capacity Resources obtained through bilateral contract; (ii) the results of prior Reliability Pricing Model Auctions, if any, for such Delivery Year (including consideration of any restriction imposed as a consequence of a prior failure to offer); and (iii) such other information as may be available to the Office of the Interconnection. The Office of the Interconnection shall reject Sell Offers or portions of Sell Offers for Capacity Resources in excess of the quantity of installed capacity from such Capacity Market Seller's Capacity Resource that it determines to be available for sale.

(b) The Office of the Interconnection shall determine the quantity of installed capacity available for sale in a Base Residual Auction or Incremental Auction as of the beginning of the period during which Buy Bids and Sell Offers are accepted for such auction, as applicable, in accordance with the time schedule set forth in the PJM Manuals. Removal of a resource from Capacity Resource status shall not be reflected in the determination of available installed capacity unless the associated unit-specific bilateral transaction is approved, the designation of such resource (or portion thereof) as a network resource for the external load is demonstrated to the Office of the Interconnection, or equivalent evidence of a firm external sale is provided prior to the deadline established therefor. The determination of available installed capacity shall also take into account, as they apply in proportion to the share of each resource owned or controlled by a Capacity Market Seller, any approved capacity modifications, and existing capacity commitments established in a prior RPM Auction, an FRR Capacity Plan, Locational UCAP transactions and/or replacement capacity transactions under this Attachment DD. To enable the Office of the Interconnection to make this determination, no bilateral transactions for Capacity Resources applicable to the period covered by an auction will be processed from the beginning of the period for submission of Sell Offers and Buy Bids, as appropriate, for that auction until completion of the clearing determination for such auction. Processing of such bilateral transactions will reconvene once clearing for that auction is completed. A Generation Capacity Resource located in the PJM Region shall not be removed from Capacity Resource status to the extent the resource is committed to service of PJM loads as a result of an RPM Auction, FRR Capacity Plan, Locational UCAP transaction and/or by designation as a replacement resource under this Attachment DD.

(c) In order for a bilateral transaction for the purchase and sale of a Capacity Resource to be processed by the Office of the Interconnection, both parties to the transaction must notify the Office of the Interconnection of the transfer of the Capacity Resource from the seller to the buyer in accordance with procedures established by the Office of the Interconnection and set forth in the PJM Manuals. If a material change with respect to any of the prerequisites for the application of Section 5.6.6 to the Generation Capacity Resource occurs, the Capacity Resource Owner shall immediately notify the Market Monitoring Unit and the Office of the Interconnection.

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. 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.

b) Resource Make-Whole Payments

If a Sell Offer specifies a minimum block, and only a portion of such block is needed to clear the market in a Base Residual or Incremental Auction, the MW portion of such Sell Offer needed to clear the market shall clear, and such Sell Offer shall set the marginal value of system capacity. In addition, the Capacity Market Seller shall receive a Resource Make-Whole Payment equal to the Capacity Resource Clearing Price in such auction times the difference between the Sell Offer's minimum block MW quantity and the Sell Offer's cleared MW quantity. If the Sell Offer price of a cleared Seasonal Capacity Performance Resource exceeds the applicable Capacity Resource Clearing Price, the Capacity Market Seller shall receive a Resource Make-Whole Payment equal to the difference between the Sell Offer price and Capacity Resource Clearing Price in such RPM Auction. The cost for any such Resource Make-Whole Payments required in a Base Residual Auction or Incremental Auction for adjustment of prior capacity commitments shall be collected pro rata from all LSEs in the LDA in which such payments were made, based on their Daily Unforced Capacity Obligations. The cost for any such Resource Make-Whole

Payments required in an Incremental Auction for capacity replacement shall be collected from all Capacity Market Buyers in the LDA in which such payments were made, on a pro-rata basis based on the MWs purchased in such auction.

c) New Entry Price Adjustment

A Capacity Market Seller that submits a Sell Offer based on a Planned Generation Capacity Resource that clears in the BRA for a Delivery Year may, at its election, submit Sell Offers with a New Entry Price Adjustment in the BRAs for the two immediately succeeding Delivery Years if:

1. Such Capacity Market Seller provides notice of such election at the time it submits its Sell Offer for such resource in the BRA for the first Delivery Year for which such resource is eligible to be considered a Planned Generation Capacity Resource. When the Capacity Market Seller provides notice of such election, it must specify whether its Sell Offer is contingent upon qualifying for the New Entry Price Adjustment. The Office of the Interconnection shall not clear such contingent Sell Offer if it does not qualify for the New Entry Price Adjustment.

2. All or any part of a Sell Offer from the Planned Generation Capacity Resource submitted in accordance with section 5.14(c)(1) is the marginal Sell Offer that sets the Capacity Resource Clearing Price for the LDA.

3. Acceptance of all or any part of a Sell Offer that meets the conditions in section 5.14(c)(1)-(2) in the BRA increases the total Unforced Capacity committed in the BRA (including any minimum block quantity) for the LDA in which such Resource will be located from a megawatt quantity below the LDA Reliability Requirement, minus the Short Term Resource Procurement Target, to a megawatt quantity at or above a megawatt quantity at the price-quantity point on the VRR Curve at which the price is 0.40 times the applicable Net CONE divided by (one minus the pool-wide average EFORd).

4. Such Capacity Market Seller submits Sell Offers in the BRA for the two immediately succeeding Delivery Years for the entire Unforced Capacity of such Generation Capacity Resource committed in the first BRA under section 5.14(c)(1)-(2) equal to the lesser of: A) the price in such seller's Sell Offer for the BRA in which such resource qualified as a Planned Generation Capacity Resource that satisfies the conditions in section 5.14(c)(1)-(3); or B) 0.90 times the Net CONE applicable in the first BRA in which such Planned Generation Capacity Resource meeting the conditions in section 5.14(c)(1)-(3) cleared, on an Unforced Capacity basis, for such LDA.

5. If the Sell Offer is submitted consistent with section 5.14(c)(1)-(4) the foregoing conditions, then:

(i) in the first Delivery Year, the Resource sets the Capacity Resource Clearing Price for the LDA and all cleared resources in the LDA receive the Capacity Resource Clearing Price set by the Sell Offer as the marginal offer, in accordance with sections 5.12(a) and 5.14(a).

(ii) in either of the subsequent two BRAs, if any part of the Sell Offer from the Resource clears, it shall receive the Capacity Resource Clearing Price for such LDA for its cleared capacity and for any additional minimum block quantity pursuant to section 5.14(b); or

(iii) if the Resource does not clear, it shall be deemed resubmitted at the highest price per MW-day at which the megawatt quantity of Unforced Capacity of such Resource that cleared the first-year BRA will clear the subsequent-year BRA pursuant to the optimization algorithm described in section 5.12(a) of this Attachment, and

(iv) the resource with its Sell Offer submitted shall clear and shall be committed to the PJM Region in the amount cleared, plus any additional minimum-block quantity from its Sell Offer for such Delivery Year, but such additional amount shall be no greater than the portion of a minimum-block quantity, if any, from its first-year Sell Offer satisfying section 5.14(c)(1)-(3) that is entitled to compensation pursuant to section 5.14(b) of this Attachment; and

(v) the Capacity Resource Clearing Price, and the resources cleared, shall be re-determined to reflect the resubmitted Sell Offer. In such case, the Resource for which the Sell Offer is submitted pursuant to section 5.14(c)(1)-(4) shall be paid for the entire committed quantity at the Sell Offer price that it initially submitted in such subsequent BRA. The difference between such Sell Offer price and the Capacity Resource Clearing Price (as well as any difference between the cleared quantity and the committed quantity), will be treated as a Resource Make-Whole Payment in accordance with Section 5.14(b). Other capacity resources that clear the BRA in such LDA receive the Capacity Resource Clearing Price as determined in Section 5.14(a).

6. The failure to submit a Sell Offer consistent with Section 5.14(c)(i)-(iii) in the BRA for Delivery Year 3 shall not retroactively revoke the New Entry Price Adjustment for Delivery Year 2. However, the failure to submit a Sell Offer consistent with section 5.14(c)(4) in the BRA for Delivery Year 2 shall make the resource ineligible for the New Entry Pricing Adjustment for Delivery Years 2 and 3.

7. For each Delivery Year that the foregoing conditions are satisfied, the Office of the Interconnection shall maintain and employ in the auction clearing for such LDA a separate VRR Curve, notwithstanding the outcome of the test referenced in Section 5.10(a)(ii) of this Attachment.

8. On or before August 1, 2012, PJM shall file with FERC under FPA section 205, as determined necessary by PJM following a stakeholder process, tariff changes to establish a long-term auction process as a not unduly discriminatory means to provide adequate

long-term revenue assurances to support new entry, as a supplement to or replacement of this New Entry Price Adjustment.

d) Qualifying Transmission Upgrade Payments

A Capacity Market Seller that submitted a Sell Offer based on a Qualifying Transmission Upgrade that clears in the Base Residual Auction shall receive a payment equal to the Capacity Resource Clearing Price, including any Locational Price Adder, of the LDA into which the Qualifying Transmission Upgrade is to increase Capacity Emergency Transfer Limit, less the Capacity Resource Clearing Price, including any Locational Price Adder, of the LDA from which the upgrade was to provide such increased CETL, multiplied by the megawatt quantity of increased CETL cleared from such Sell Offer. Such payments shall be reflected in the Locational Price Adder determined as part of the Final Zonal Capacity Price for the Zone associated with such LDAs, and shall be funded through a reduction in the Capacity Transfer Rights allocated to Load-Serving Entities under section 5.15, as set forth in that section. PJMSettlement shall be the Counterparty to any cleared capacity transaction resulting from a Sell Offer based on a Qualifying Transmission Upgrade.

e) Locational Reliability Charge

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. PJMSettlement shall be the Counterparty to the LSEs' obligations to pay, and payments of, Locational Reliability Charges.

f) The Office of the Interconnection shall determine Zonal Capacity Prices in accordance with the following, based on the optimization algorithm:

i) The Office of the Interconnection shall calculate and post the Preliminary Zonal Capacity Prices for each Delivery Year following the Base Residual Auction for such Delivery Year. The Preliminary Zonal Capacity Price for each Zone shall be the sum of: 1) the marginal value of system capacity for the PJM Region, without considering locational constraints; 2) the Locational Price Adder, if any, for the LDA in which such Zone is located; provided however, that if the Zone contains multiple LDAs with different Capacity Resource Clearing Prices, the Zonal Capacity Price shall be a weighted average of the Capacity Resource Clearing Prices for such LDAs, weighted by the Unforced Capacity of Capacity Resources cleared in each such LDA; 3) an adjustment, if required, to account for adders paid to Annual Resources and Extended Summer Demand Resources in the LDA for which the zone is located; 4) an adjustment, if required, to account for Resource Make-Whole Payments; and (5) an adjustment, if required to provide sufficient revenue for payment of any PRD Credits, all as determined in accordance with the optimization algorithm.

ii) The Office of the Interconnection shall calculate and post the Adjusted Zonal Capacity Price following each Incremental Auction. The Adjusted Zonal Capacity Price for each Zone shall equal the sum of: (1) the average marginal value of system capacity weighted by the Unforced Capacity cleared in all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); (2) the average Locational Price Adder weighted by the Unforced Capacity cleared in all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); (3) an adjustment, if required, to account for adders paid to Annual Resources and Extended Summer Demand Resources for all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); (4) an adjustment, if required, to account for Resource Make-Whole Payments for all actions previously conducted (excluding any Resource Make-Whole Payments to be charged to the buyers of replacement capacity); and (5) an adjustment, if required to provide sufficient revenue for payment of any PRD Credits. The Adjusted Zonal Capacity Price may decrease if Unforced Capacity is decommitted or the Resource Clearing Price decreases in an Incremental Auction.

iii) The Office of the Interconnection shall calculate and post the Final Zonal Capacity Price for each Delivery Year after the final auction is held for such Delivery Year, as set forth above. The Final Zonal Capacity Price for each Zone shall equal the Adjusted Zonal Capacity Price, as further adjusted to reflect any decreases in the Nominated Demand Resource Value of any existing Demand Resource cleared in the Base Residual Auction and Second Incremental Auction.

g) Resource Substitution Charge

Each Capacity Market Buyer in an Incremental Auction securing replacement capacity shall pay a Resource Substitution Charge equal to the Capacity Resource Clearing Price resulting from such auction multiplied by the megawatt quantity of Unforced Capacity purchased by such Market Buyer in such auction.

h) Minimum Offer Price Rule for Certain ~~Generation~~ Capacity Resources

(1) **General Rule.** Any Sell Offer based on either a New Entry Capacity Resource or a Cleared Capacity Resource with a State Subsidy submitted in any RPM Auction shall have an offer price no lower than the applicable MOPR Floor Offer Price, unless the Capacity Market Seller qualifies for an exemption with respect to such Capacity Resource with a State Subsidy prior to the submission of such offer.

(A) Effect of Exemption. To the extent a Sell Offer in any RPM Auction is based on a Capacity Resource with State Subsidy, a combustion turbine resource, or a combined cycle resource and qualifies for any of the exemptions defined in Tariff, Attachment DD, sections 5.14(h)(4)-(8), the Sell Offer for such resource shall not be limited by the MOPR Floor Offer Price.

(B) Effect of Exception. To the extent a Sell Offer in any RPM Auction for any Delivery Year is based on a Capacity Resource with State Subsidy, a combustion turbine resource, or a combined cycle resource for which the Capacity Market Seller obtains, prior to the submission of such offer, a resource-specific exception, such offer may include an offer price below the default MOPR Floor Offer Price applicable to such resource type, but no lower than the resource-specific MOPR Floor Offer Price determined in such exception process.

(C) Process for Establishing a Capacity Resource with a State Subsidy.

(i) By no later than one hundred and twenty (120) 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 certify to the Office of Interconnection, in accordance with the PJM Manuals, whether or not each Capacity Resource (other than Demand Resource and Energy Efficiency Resource) that the Capacity Market Seller intends to offer into the RPM Auction qualifies as a Capacity Resource with a State Subsidy (including by way of Jointly Owned Cross-Subsidized Capacity Resource) and identify (with specificity) any State Subsidy. Capacity Market Sellers that intend to offer a Demand Resource or an Energy Efficiency Resource into the RPM Auction shall certify to the Office of Interconnection, in accordance with the PJM Manuals, whether or not such Demand Resource or Energy Efficiency Resource qualifies as a Capacity Resource with a State Subsidy no later than thirty (30) 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. All Capacity Market Sellers shall be responsible for each certification irrespective of any guidance developed by the Office of the Interconnection and the Market Monitoring Unit. A Capacity Resource shall be deemed a Capacity Resource with State Subsidy if the Capacity Market Seller fails to timely certify whether or not a Capacity Resource is entitled to a State Subsidy, unless the Capacity Market Seller receives a waiver from the Commission or the Capacity Resource previously received a resource-specific exception pursuant to Tariff, Attachment DD, section 5.14(h)(3).

(ii) The requirements in subsection (i) above do not apply to Capacity Resources for which the Market Seller designated whether or not it is subject to a State Subsidy and the associated subsidies to which the Capacity Resource is entitled in a prior Delivery Year, unless there has been a change in the set of those State Subsidy(ies), or for those which are eligible for the Demand Resource or Energy Efficiency exemption, Capacity Storage Resource exemption, Self-Supply Entity exemption, or the Intermittent Resource exemption.

(iii) Once a Capacity Market Seller has certified a Capacity Resource as a Capacity Resource with a State Subsidy, the status of such Capacity Resource will remain unchanged unless and until the Capacity Market Seller (or a subsequent Capacity Market Seller) that owns or controls such Capacity Resource provides a certification of a change in such status, the Office of the Interconnection removes such status, or by FERC order. All Capacity Market Sellers shall have an ongoing obligation to certify to the Office of Interconnection and the Market Monitoring Unit a Capacity Resource's change in status as a Capacity Resource with State Subsidy within 5 days of such change.

(2) **Minimum Offer Price Rule.** Any Sell Offer for a New Entry Capacity Resource or a Cleared Capacity Resource with State Subsidy that does not qualify for any of the exemptions, as defined in Tariff, Attachment DD, sections 5.14(h)(5)-(8), shall have an offer price no lower than the applicable MOPR Floor Offer Price.

(A) New Entry MOPR Floor Offer Price. For a New Entry Capacity Resource the applicable MOPR Floor Offer Price, based on the net cost of new entry for each resource type, shall be, at the election of the Capacity Market Seller, (i) the resource-specific value determined in accordance with the resource-specific MOPR Floor Offer Price process in Tariff, Attachment DD, section 5.14(h)(3) below or (ii) if applicable, the default New Entry MOPR Floor Offer Price for the applicable resource based on the gross cost of new entry values shown in the table below, as adjusted for Delivery Years subsequent to the 2022/2023 Delivery Year, net of estimated net energy and ancillary service revenues for the resource type and Zone in which the resource is located.

Resource Type	**Gross Cost of New Entry (2022/2023 $/ MW-day) (Nameplate)***
Nuclear	$2,000
Coal	$1,068
Combined Cycle	$320
Combustion Turbine	$294
Fixed Solar PV	$290
Tracking Solar PV	$271
Onshore Wind	$420
Offshore Wind	$1,155
Battery Energy Storage	$532
Generation Backed Demand Resource	$254

* The gross cost of new entry values are expressed in dollars per MW-day in terms of nameplate megawatts. The cost of new entry values are ultimately converted to Installed Capacity ("ICAP") MW-day, where the ICAP MW value for fixed Solar PV, tracking Solar PV, Onshore Wind and Offshore Wind is assumed to be 42.0%, 60%, 17.6%, and 26.0%, respectively, of the nameplate rating of these resource types.

The default New Entry MOPR Floor Offer Price for load-backed Demand Resources (i.e., the MW portion of Demand Resources that is not supported by generation) shall be separately determined for each Locational Deliverability Area as the MW-weighted average offer price of load-backed Demand Resources from the most recent three Base Residual Auctions, where the MW weighting shall be determined based on the portion of each Sell Offer for a load-backed portion of the Demand Resource that is supported by end-use customer locations on the registrations used in the pre-registration process for such Base Residual Auctions, as described in the PJM Manuals.

The default New Entry MOPR Floor Offer Price for Energy Efficiency Resources shall be $64/ICAP MW-Day (Net Cost of New Entry).

Commencing with the Base Residual Auction for the 2023/2024 Delivery Year, the Office of the Interconnection shall adjust the default gross costs of new entry in the table above and for load-backed Demand Resources, and post the preliminary estimates of the adjusted applicable default New Entry MOPR Floor Offer Prices 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 default New Entry MOPR Floor Offer Prices for all resource types except for load-backed Demand Resources and Energy Efficiency Resources, the Office of the Interconnection shall adjust the gross costs of new entry utilizing, for combustion turbine and combined cycle resource types, 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 for all other resource types, the "BLS Producer Price Index Turbines and Turbine Generator Sets" component of the Applicable BLS Composite Index used to determine the Variable Resource Requirement Curve shall be replaced with the "BLS Producer Price Index Final Demand, Goods Less Food & Energy, Private Capital Equipment" when adjusting the gross costs of new entry. The resultant value shall then be then adjusted further by a factor of 1.022 for nuclear, coal, combustion turbine, and combine cycle resource types or 1.01 for solar, wind, and storage resource types to reflect the annual decline in bonus depreciation scheduled under federal corporate tax law. Updated estimates of the net energy and ancillary service revenues for each default resource type and applicable Zone, which shall include, but are not limited to, consideration of Fuel Costs, Maintenance Adders and Operating Costs, as applicable, pursuant to Operating Agreement, Schedule 2 shall then be subtracted from the adjusted gross costs of new entry to determine the adjusted New Entry MOPR Floor Offer Price. The net energy and ancillary services revenue is equal to the average of the annual net revenues of the three most recent calendar years preceding the Base Residual Auction, where such annual net revenues shall be determined in accordance with the following and the PJM Manuals:

(i) for nuclear resource type, the net energy and ancillary services revenue estimate shall be determined by the gross energy market revenue determined by the product of [average annual zonal day-ahead LMP times 8,760 hours times the annual average equivalent availability factor of all PJM nuclear resources] minus the total annual cost to produce energy determined by the product of [8,760 hours times the annual average equivalent availability factor of all PJM nuclear resources times $9.02/MWh for a single unit plant or $7.66/MWh for a multi-unit plant] where these hourly cost rates include fuel costs and variable operation and maintenance expenses, inclusive of Maintenance Adder costs, plus an ancillary services revenue of $3,350/MW-year;

(ii) for coal resource type, the net energy and ancillary services revenue estimate shall be determined by a simulated dispatch of a 650 MW coal unit (with heat rate of 8,638 BTU/kWh and variable operations and maintenance variable operation and maintenance expenses, inclusive of Maintenance Adder costs, of $9.50/MWh) using applicable coal prices, as set forth in the PJM Manuals, and an ancillary services revenue of $3,350/MW-year. The unit is committed day-ahead in profitable blocks of at least eight hours, and then committed in real-time for profitable hours if not already committed day ahead;

(iii) for combustion turbine resource type, the net energy and ancillary services revenue estimate shall be determined in a manner consistent with the methodology described in Tariff, Attachment DD, section 5.10(a)(v)(B) for the Reference Resource combustion turbine.

(iv) for combined cycle resource type, the net energy and ancillary services revenue estimate shall be determined in the same manner as that prescribed for a combustion turbine resource type, except that the heat rate assumed for the combined cycle resource shall be 6,553 BTU/kwh, the variable operations and maintenance expenses for such resource, inclusive of Maintenance Adder costs, shall be $2.11/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 Peak-Hour Dispatch, 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 services revenue shall be $3,350/MW-year.

(v) for solar PV resource type, the net energy and ancillary services revenue estimate shall be determined using a solar resource model that provides the average MW output level, expressed as a percentage of nameplate rating, by hour of day (for each of the 24-hours of a day) and by calendar month (for each of the twelve months of a year). The annual net energy market revenues are determined by multiplying the solar output level of each hour by the real-time zonal LMP applicable to such hour with this product summed across all of the hours of an annual period, plus an ancillary services revenue of $3,350/MW-year. Two separate solar resource models are used, one model for a fixed panel resource and a second model for a tracking panel resource;

(vi) for onshore wind resource type, the net energy and ancillary services revenue estimate shall be determined using a wind resource model that provides the average MW output level, expressed as a percentage of nameplate rating, by hour of day (for each of the 24-hours of a day) and by calendar month (for each of the twelve months of a year). The annual energy market revenues are determined by multiplying the wind output level of each hour by the real-time zonal LMP applicable to such hour with this product summed across all of the hours of an annual period, plus an ancillary services revenue of $3,350/MW-year;

(vii) for offshore wind resource type, the net energy and ancillary services revenue estimate shall be the product of [the average annual zonal real-time LMP times 8,760 hours times an assumed annual capacity factor of 45%], plus an ancillary services revenue of $3,350/MW-year;

(viii) for Capacity Storage Resource, the net energy and ancillary services revenue estimate shall be estimated by a simulated dispatch against historical real-time zonal LMPs where the resource is assumed to be dispatched for the four hours of highest LMP of a daily twenty-four hour period if the average LMP of these four hours exceeds 120% of the average LMP of the four lowest LMP hours of the same twenty-four hour period. The net energy market revenues will be determined by the product of [hourly output of 1 MW times the hourly LMP for each hour of assumed discharging] minus the product of [hourly consumption of 1.2 MW times the hourly LMP for each hour of assumed charging] with this net value summed across all of the hours of an annual period, plus an ancillary services revenue of $3,350/MW-year. An 83.3% efficiency of the battery energy storage resource is reflected by assuming each 1.0 MW of discharge requires 1.2 MW of charge; and

(ix) for generation-backed Demand Resource, the net energy and ancillary services revenue estimate shall be zero dollars.

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 gross cost of new entry values. 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 gross cost of new entry values stated in the table above and the default New Entry MOPR Floor Offer Price for Energy Efficiency Resources. 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 gross cost of new entry values or the default New Entry MOPR Floor Offer Price for Energy Efficiency 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.

New Entry Capacity Resources for which there is no default MOPR Floor Offer Price provided in accordance with this section must seek a resource-specific value determined in accordance with the resource-specific MOPR Floor Offer Price process below to participate in an RPM Auction. Failure to obtain a resource-specific MOPR Floor Offer Price will result in the Office of the Interconnection rejecting any Sell Offer based on such resource for the relevant RPM Auction.

(B) Cleared MOPR Floor Offer Prices. For a Cleared Capacity Resource with State Subsidy, the applicable Cleared MOPR Floor Offer Price shall be, at the election of the Capacity Market Seller, (i) based on the resource-specific MOPR Floor Offer Price , as determined in accordance with Tariff, Attachment DD, section 5.14(h)(3) below, or (ii) if available, the default Avoidable Cost Rate for the applicable 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 estimated net energy and ancillary service revenues for that resource type and Zone in which the resource is located.

Existing Resource Type	**Default Gross ACR (2022/2023 ($/MW-day) (Nameplate)***
Nuclear - single	$697
Nuclear - dual	$445
Coal	$80
Combined Cycle	$56
Combustion Turbine	$50
Solar PV (fixed and tracking)	$40
Wind Onshore	$83
Generation-backed Demand Response	$3
Load-backed Demand Response	$0
Energy Efficiency	$0

* The default Avoidable Cost Rate values are expressed in dollars per MW-day in terms of nameplate megawatts. The cost of new entry values are ultimately converted to Installed Capacity ("ICAP") MW-day, where the ICAP MW value for Solar PV and

Onshore Wind is assumed to be 42.0%, and 17.6%, 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 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 10-year average Handy-Whitman Index in order to adjust the Gross ACR values to account for expected inflation and updated estimates of the net energy and ancillary service revenues, by Zone, for each default resource type, which shall include, but are not limited to, consideration of Fuel Costs, Maintenance Adders and Operating Costs, as applicable, pursuant to Operating Agreement, Schedule 2. The estimates of the net energy and ancillary services revenues shall be determined in a manner consistent with the methodology described in Tariff, Attachment DD, section 5.14(h)(2)(A) and the PJM Manuals.

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 State 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.

Cleared Capacity Resources with State Subsidy for which there is no default MOPR Floor Offer Price provided in accordance with this section must seek a resource-specific value determined in accordance with the resource-specific MOPR Floor Offer Price process below to participate in an RPM Auction. Failure to obtain a resource-specific MOPR Floor Offer Price will result in the Office of the Interconnection rejecting any Sell Offer based on such resource.

~~(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.~~

(3~~5~~) ~~Unit~~Resource-Specific Exception. A Capacity Market Seller intending to submit a Sell Offer ~~meeting the criteria in subsection (4)~~ in any RPM Auction for a New Entry Capacity Resource or a Cleared Capacity Resource with State Subsidy below the applicable default MOPR Floor Offer Price may, at its election, submit a request for a resource-specific exception for such Capacity Resource. A Sell Offer below the default MOPR Floor Offer Price, but no lower than the resource-specific MOPR Floor Offer Price, 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~~approval from the Office of the Interconnection or the Commission, prior to the RPM Auction in which it seeks to submit the Sell Offer.~~, that~~ S~~s~~uch 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 exclusive of any State Subsidy~~from PJM-administered markets~~. All supporting data must be provided for all requests. The following ~~process and~~ requirements shall apply to requests for such determinations:

(A~~i~~) The Capacity Market Seller ~~may request such a determination by~~ shall submit a written request with all of the required documentation as described below and in the PJM Manuals. For such purpose, the Capacity Market Seller shall submit the resource-specific exception request to the Office of the Interconnection and the Market Monitoring Unit 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~~ default Minimum Floor Offer Prices, determined pursuant to Tariff, Attachment DD, sections 5.14(h)(2)(A) and (B). If the final applicable default Minimum Floor Offer Price 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.

(B~~ii~~) For a resource-specific exception for a New Entry Capacity Resource~~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~~Capacity R~~r~~esource, as well as estimates of offsetting net revenues.

The financial modeling assumptions for calculating Cost of New Entry for Generation Capacity Resources and generation-backed Demand Resources shall be: (i) nominal levelization of gross costs, (ii) asset life of twenty years, (iii) no residual value, (iv) all project costs included with no sunk costs excluded, (v) use first year revenues (which may include revenues from the sale of renewable energy credits for purposes other than state-mandated or state-sponsored programs), and (vi) weighted average cost of capital based on the actual cost of capital for the entity proposing to build the Capacity Resource. Notwithstanding the foregoing, a Capacity Market Seller that seeks to utilize an asset life other than twenty years (but no greater than 35 years) shall provide evidence to support the use of a different asset life, including but not limited to, the asset life term for such resource as utilized in the Capacity Market Seller's financial accounting (*e.g.*, independently audited financial statements), or project financing documents for the resource or evidence of actual costs or financing assumptions of recent comparable projects to the extent the seller has not executed project financing for the resource (*e.g.*, independent project engineer opinion or manufacturer's performance guarantee), or opinions of third-party experts regarding the reasonableness of the financing assumptions used for the project itself or in comparable projects. Capacity Market Sellers may also rely on evidence presented in federal filings, such as its FERC Form No. 1 or an SEC Form 10-K, to demonstrate an asset life other than 20 years of similar asset projects.

~~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, s~~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~~ 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~~n~~ resource-specific exception hereunder. The request also shall identify all revenue sources (exclusive of any State Subsidies) 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. Any evaluation of net revenues should be consistent with Operating Agreement, Schedule 2, including, but not limited to, consideration of Fuel Costs, Maintenance Adders and Operating Costs, as applicable.~~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.~~

The default assumptions for calculating resource-specific Cost of New Entry for Energy Efficiency Resources shall be based on, as supported by documentation provided by the Capacity Market Seller: the nominal-levelized annual cost to implement the Energy Efficiency program or to install the Energy Efficiency measure reflective of the useful life of the implemented Energy Efficiency equipment, and the offsetting savings associated with avoided wholesale energy costs and other claimed savings provided by implementing the Energy Efficiency program or installing the Energy Efficiency measure.

The default assumptions for calculating resource-specific Cost of New Entry for load-backed Demand Resources shall be based on, as supported by documentation provided by the Capacity Market Seller, program costs required for the resource to meet the capacity obligations of a Demand Resource, including all fixed operating and maintenance cost and weighted average cost of capital based on the actual cost of capital for the entity proposing to develop the Demand Resource.

For generation-backed Demand Resources, the determination of a resource-specific MOPR Floor Offer Price shall only consider the resource's costs related to participation in the Reliability Pricing Model and meeting a capacity commitment. The Capacity Market Seller must provide supporting documentation (at the end-use customer level) of the cost associated with participation as a Demand Resource and an attestation from the Demand Resource that all other costs are not related to participation as a Demand Resource, such as the costs associated with installation and operation of the generation unit, and will be accrued and paid regardless of participation in the Reliability Pricing Model. To the extent the Capacity Market Seller includes all costs associated with the generation unit supporting the Demand Resource then demand charge management benefits at the retail level (as supported by documentation at the end-use customer level) may also be considered as an additional offset to such costs. Supporting documentation (at the end-use customer level) may include, but is not limited to, historic end-use customer bills and associated analysis that identifies the annual retail avoided cost from the operation of such generation unit or the business case to support installation of the generator or regulatory requirements where the generator would be required absent participation in the Reliability Pricing Model.

(C) For a Resource-Specific Exception for a Cleared Capacity Resource with State Subsidy that is a generation resource, the Capacity Market Seller shall submit a Sell Offer consistent with the unit-specific Market Seller Offer Cap process pursuant to Tariff, Attachment DD, section 6.8; except that the 10% uncertainty adder may not be included in the "Adjustment Factor." In addition and notwithstanding the requirements of Tariff, Attachment DD, section 6.8, the Capacity Market Seller may, at its election, include in its request for an exception under this subsection documentation to support projected energy and ancillary services markets revenues. Such a request shall identify all revenue sources (exclusive of any State Subsidies) 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. Any evaluation of revenues should include, but would not be not limited to, consideration of Fuel Costs, Maintenance Adders and Operating Costs, as applicable, pursuant to Operating Agreement, Schedule 2.

The resource-specific MOPR Floor Offer Price for a Cleared Capacity Resource with State Subsidy that is a generation-backed Demand Resource will be determined based on only costs associated with the resource participating in the Reliability Pricing Model and satisfying a capacity commitment or, to the extent the Capacity Market Seller includes all costs associated with the generation unit supporting the Demand Resource, then demand charge management benefits at the retail level (as supported by documentation at the end-use customer level) may also be considered as an additional offset to such costs. Supporting documentation (at the end-use customer level) may include but is not limited to, historic end-use customer bills and associated analysis that identifies the annual retail avoided cost from the operation of such generation unit or the business case to support installation of the generator or regulatory requirements where the generator would be required absent participation in the Reliability Pricing Model.

(D~~iii~~) A Sell Offer evaluated at the resource-specific exception ~~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 default MOPR Floor Offer Price~~minimum offer level prescribed by subsection (4)~~, based on competitive cost advantages relative to the costs estimated by the default MOPR Floor Offer Price~~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 those estimated by the default MOPR Floor Offer Price~~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 a~~n~~ resource-specific exception ~~hereunder~~ by the Office of the Interconnection.

(E) The Capacity Market Seller must submit a sworn, notarized certification of a duly authorized officer, certifying that the officer has personal knowledge of the resource-specific exception request and that to the best of his/her knowledge and belief: (1) the information supplied to the Market Monitoring Unit and the Office of Interconnection to support its request for an exception is true and correct; (2) the Capacity Market Seller has disclosed all material facts relevant to the request for the exception; and (3) the request satisfies the criteria for the exception.

(F~~iv~~) The Market Monitoring Unit shall review, in an open and transparent manner with the Capacity Market Seller and the Office of the Interconnection, 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, in an open and transparent manner, 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~~ After the Office of the Interconnection determines with the advice and input of Market Monitor, the acceptable minimum ~~that the requested~~ Sell Offer ~~is acceptable~~, the Capacity Market Seller s~~S~~hall 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, and in making such determination, the Capacity Market Seller may consider the applicable default MOPR Floor Offer Price and may select such default value if it is lower than the resource-specific determination. 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 based on the lower of the applicable default MOPR Floor Offer Price and the resource-specific determination unless and until ordered to do otherwise by FERC.

(4) Competitive Exemption.

(A) A Capacity Resource with State Subsidy may be exempt from the Minimum Offer Price Rule in any RPM Auction if the Capacity Market Seller certifies to the Office of Interconnection, in accordance with the PJM Manuals, that the Capacity Market Seller of such Capacity Resource elects to forego receiving any State 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. Notwithstanding the foregoing, the competitive exemption is not available to Capacity Resources with State Subsidy that (A) are owned or offered by Self-Supply Entities, (B) are no longer entitled to receive a State Subsidy but are still considered a Capacity Resource with State Subsidy solely because they have not cleared an RPM Auction since last receiving a State Subsidy, (C) are Jointly Owned Cross-Subsidized Capacity Resources or is the subject of a bilateral transaction (including but not limited to those reported pursuant to Tariff, Attachment DD, section 4.6) and not all Capacity Market Sellers of the supporting facility unanimously elect the competitive exemption and certify that no State Subsidy will be received associated with supporting the resource, or (D) a natural gas fired combined cycle or combustion turbine resource.

(B) (i) The Capacity Market Seller shall not receive a State Subsidy for any part of the relevant Delivery Year in which it elects a competitive exemption or certifies that it is not a Capacity Resource with State Subsidy. In furtherance of this prohibition, if a Capacity Resource that (1) is a New Entry Capacity Resource that elects the competitive exemption in subsection (4)(A) above and clears an RPM Auction for a given Delivery Year, but prior to the end of that Delivery Year elects to accept a State Subsidy or (2) is not a Capacity Resource with State Subsidy at the time of the RPM Auction for the Delivery Year for which it first cleared an RPM Auction but prior to the end of that Delivery Year receives a State Subsidy for the associated Delivery Year or an earlier Delivery Year, then the Capacity Market Seller of that Capacity Resource shall not receive RPM revenues for any part of that Delivery Year and may not participate in any RPM Auction with such resource, or be eligible to use such resource as replacement capacity starting June 1 of the Delivery Year after the Capacity Market Seller first receives the State Subsidy and continuing for a period of 20 years, except for battery energy storage, for which such participation restriction shall apply for a period of 15 years. A Jointly Owned Cross-Subsidized Capacity Resource that meets the requirements of either of the two preceding subsections (B)(i)(1) or (2), shall not receive RPM revenues for any part of that Delivery Year and may not participate in any RPM Auction or be eligible to be used as replacement capacity starting June 1 of the Delivery Year and continuing for the number of years specified above, after any joint Capacity Market Seller of the underlying facility first receives the State Subsidy. A Capacity Resource with State Subsidy that is the subject of a bilateral transaction that meets the requirements of either of the two preceding subsections (B)(i)(1) or (2) shall not receive RPM revenues for any part of that Delivery Year and may not participate in any RPM Auction or be eligible to be used as replacement capacity starting June 1 of the Delivery Year and continuing for the number of years specified above if any owner or Capacity Market Seller of the facility receives a State Subsidy. The Capacity Market Seller(s) of any such Capacity Resource or Jointly Owned Cross-Subsidized Capacity Resource shall also return to the Office of the Interconnection any revenues paid to such Capacity Resource associated with their capacity commitment for such Delivery Year and shall retain their RPM commitment and associated obligations for such Delivery Year and for any future Delivery Years in which the resource has already secured a capacity commitment, including any Non-Performance Charges relating to the capacity and remain eligible to collect Performance Payments under this Tariff, Attachment DD, section 10A for the relevant Delivery Year and any subsequent Delivery Years for which it already received an RPM commitment. Notwithstanding the foregoing, Capacity Resources that lose their eligibility to participate in RPM pursuant to this section remain eligible for commitment in an FRR Capacity Plan.

(ii) If any Capacity Resource that has previously cleared an RPM Auction (1) is a Cleared Capacity Resource with State Subsidy that claims the competitive exemption pursuant to subsection (4)(A) above in an RPM Auction and clears such RPM Auction or (2) was not a Capacity Resource with State Subsidy at the time it cleared an RPM Auction for a given Delivery Year but later becomes entitled to receive a State Subsidy for that Delivery Year, and the Capacity Market Seller subsequently elects to accept a State Subsidy for any part of that Delivery Year, then the Capacity Market Seller of that Capacity Resource may not receive RPM revenues for any part of that Delivery Year, unless it can demonstrate that it would have cleared in the relevant RPM Auction under an offer consistent with the resource-specific exception process outlined above in subsection 5.14(h)(3). All Capacity Market Sellers of a Jointly Owned Cross-Subsidized Capacity Resource that meets the requirements of either of the two preceding subsections (B)(ii)(1) or (2) may not receive RPM revenues for any part of that Delivery Year if any joint Capacity Market Seller of the underlying facility accepts a subsidy for that Delivery Year, unless the Capacity Market Seller can demonstrate that the facility would have cleared in the relevant RPM Auction under an offer consistent with the resource-specific exception process outlined above in subsection 5.14(h)(3). A Capacity Resource with State Subsidy that is the subject of a bilateral transaction may not receive RPM revenues for any part of that Delivery Year if any owner or Capacity Market Seller of the underlying facility receives a State Subsidy for that Delivery Year, unless the Capacity Market Seller can demonstrate that the facility would have cleared in the relevant RPM Auction under an offer consistent with the resource-specific exception process outlined above in subsection 5.14(h)(3), if any owner or Capacity Market Seller of the facility receives a State Subsidy. The Capacity Market Seller(s) of any such Capacity Resources or Jointly Owned Cross-Subsidized Capacity Resource shall return to the Office of the Interconnection any revenues paid to such Capacity Resource associated with their capacity commitment for such Delivery Year and shall retain their RPM commitment and associated obligations for the relevant Delivery Year and remain eligible to collect Performance Payments or to pay Non-Performance Charges, as applicable, pursuant to Tariff, Attachment DD, section 10A.

(iii) Any revenues returned to the Office of the Interconnection pursuant to the preceding subsections (i) and (ii) shall be allocated to the relevant load that paid for the State Subsidy (to the extent possible). If the Office of Interconnection cannot identify the relevant load responsible for the State Subsidy, then the returned revenues would be allocated across all load in the RTO that has not selected the FRR Alternative. Such revenues shall be distributed on a pro-rata basis to such LSEs that were charged a Locational Reliability Charge based on their Daily Unforced Capacity Obligations.

(5) Self-Supply Entity exemption. A Capacity Resource that is owned, or bilaterally contracted, by a Self-Supply Entity on or before December 19, 2019, shall be exempt from the Minimum Offer Price Rule if such Capacity Resource satisfies at least one of the criteria specified below:

(A) has successfully cleared an RPM Auction prior to December 19, 2019;

(B) is the subject of an interconnection construction service agreement, interim interconnection service agreement, interconnection service agreement or equivalent agreement executed on or before December 19, 2019; or

(C) is the subject of an unexecuted interconnection construction service agreement, interim interconnection service agreement, interconnection service agreement or equivalent agreement filed by PJM with the Commission on or before December 19, 2019.

(6) Intermittent Resource Exemption. A Capacity Resource with State Subsidy that is an Intermittent Resource shall be exempt from the Minimum Offer Price Rule if such Capacity Resource (1) receives or is entitled to receive State Subsidies through renewable energy credits or equivalent credits associated with a state-mandated or state-sponsored renewable portfolio standard ("RPS") program or equivalent program and (2) satisfies at least one of the following criteria:

(A) has successfully cleared an RPM Auction prior to December 19, 2019;

(B) is the subject of an interconnection construction service agreement, interim interconnection service agreement, interconnection service agreement or equivalent executed on or before December 19, 2019; or

(C) is the subject of an unexecuted interconnection construction service agreement, interim interconnection service agreement, interconnection service agreement or equivalent filed by PJM with the Commission on or before December 19, 2019.

(7) Demand Resource and Energy Efficiency Resource Exemption. A Capacity Resource with State Subsidy that is Demand Resource or an Energy Efficiency Resource shall be exempt from the Minimum Offer Price Rule if such Capacity Resource satisfies at least one of the following criteria:

(A) has successfully cleared an RPM Auction prior to December 19, 2019. For purposes of this subsection (a), individual customer location registrations (or for utility-based residential load curtailment program, based on the total number of participating customers) that participated as Demand Resource and cleared in an RPM Auction prior to December 19, 2019, and were submitted to PJM no later than 45 days prior to the BRA for the 2022/2023 Delivery Year shall be deemed eligible for the Demand Resource and Energy Efficiency Resource Exemption; or

(B) has completed registration on or before December 19, 2019; or

(C) is supported by a post-installation measurement and verification report for Energy Efficiency Resources approved by PJM on or before December 19, 2019 (calculated for each installation period, Zone and Sub-Zone by using the greater of the latest approved post-installation measurement and verification report prior to December 19, 2019 or the maximum MW cleared for a Delivery Year across all auctions conducted prior to December 19, 2019).

(8) Capacity Storage Resource Exemption. A Capacity Resource with State Subsidy that is a Capacity Storage Resource shall be exempt from the Minimum Offer Price Rule if such Capacity Storage Resource satisfies at least one of the following criteria:

(A) has successfully cleared an RPM Auction prior to December 19, 2019;

(B) is the subject of an interconnection construction service agreement, interim interconnection service agreement, interconnection service agreement or equivalent executed on or before December 19, 2019; or

(C) is the subject of an unexecuted interconnection construction service agreement, interim interconnection service agreement, interconnection service agreement or equivalent filed by PJM with the Commission on or before December 19, 2019.

(9) Procedures and Remedies in Cases of Suspected Fraud or Material Misrepresentation or Omissions in Connection with a Capacity Resource with State 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 a Capacity Resource with a State Subsidy (including whether the Capacity Resource is a Jointly Owned Cross-Subsidized Capacity Resource) or does not qualify for a competitive exemption or contains information that is inconsistent with the resource-specific exception, then:

(A) A Capacity Market Seller shall, within five (5) business days upon receipt of the request for additional information, 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 State Subsidy or whether the Capacity Market Seller is eligible for the competitive exemption. If the Office of the Interconnection determines that the Capacity Resource's status as a Capacity Resource with State Subsidy is different from that specified by the Capacity Market Seller or is not eligible for a competitive exemption pursuant to subsection (4) above, the Office of the Interconnection shall notify, in writing, the Capacity Market Seller of such determination by no later than sixty-five (65) 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, if the Office of Interconnection determines that the subject resource is a Capacity Resource with State Subsidy or is not eligible for a competitive exemption pursuant to subsection (4) above, such Capacity Resource shall be subject to the Minimum Offer Price Rule, unless and until ordered to do otherwise by FERC.

(B) if the Office of the Interconnection does not provide written notice of suspected fraudulent or material misrepresentation or omission at least sixty-five (65) 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. In such event, if the Office of Interconnection determines that a resource is a Capacity Resource with State Subsidy that is subject to the Minimum Offer Price Rule, the Office of the Interconnection will proceed with administration of the Tariff and market rules on that basis unless and until ordered to do otherwise by FERC. The Office of the Interconnection shall implement any remedies ordered by FERC; and

(C) prior to applying the Minimum Offer Price Rule, 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 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.

i) Capacity Export Charges and Credits

(1) Charge

Each Capacity Export Transmission Customer shall incur for each day of each Delivery Year a Capacity Export Charge equal to the Reserved Capacity of Long-Term Firm Transmission Service used for such export ("Export Reserved Capacity") multiplied by (the Final Zonal Capacity Price for such Delivery Year for the Zone encompassing the interface with the Control Area to which such capacity is exported minus the Final Zonal Capacity Price for such Delivery Year for the Zone in which the resources designated for export are located, but not less than zero). If more than one Zone forms the interface with such Control Area, then the amount of Reserved Capacity described above shall be apportioned among such Zones for purposes of the above calculation in proportion to the flows from such resource through each such Zone directly to such interface under CETO/CETL analysis conditions, as determined by the Office of the Interconnection using procedures set forth in the PJM Manuals. The amount of the Reserved Capacity that is associated with a fully controllable facility that crosses such interface shall be completely apportioned to the Zone within which such facility terminates.

(2) Credit

To recognize the value of firm Transmission Service held by any such Capacity Export Transmission Customer, such customer assessed a charge under section 5.14(i)(1) also shall receive a credit, comparable to the Capacity Transfer Rights provided to Load-Serving Entities under section 5.15. Such credit shall be equal to the locational capacity price difference specified in section 5.14(i)(1) times the Export Customer's Allocated Share determined as follows:

Export Customer’s Allocated Share equals

(Export Path Import * Export Reserved Capacity) /

(Export Reserved Capacity + Daily Unforced Capacity Obligations of all LSEs in such Zone).

Where:

“Export Path Import” means the megawatts of Unforced Capacity imported into the export interface Zone from the Zone in which the resource designated for export is located.

If more than one Zone forms the interface with such Control Area, then the amount of Export Reserved Capacity shall be apportioned among such Zones for purposes of the above calculation in the same manner as set forth in subsection (i)(1) above.

(3) Distribution of Revenues

Any revenues collected from the Capacity Export Charge with respect to any capacity export for a Delivery Year, less the credit provided in subsection (i)(2) for such Delivery Year, shall be distributed to the Load Serving Entities in the export-interface Zone that were assessed a

Locational Reliability Charge for such Delivery Year, pro rata based on the Daily Unforced Capacity Obligations of such Load-serving Entities in such Zone during such Delivery Year. If more than one Zone forms the interface with such Control Area, then the revenues shall be apportioned among such Zones for purposes of the above calculation in the same manner as set forth in subsection (i)(1) above.

5.14A [Reserved.]

5.14B Generating Unit Capability Verification Test Requirements Transition Provision for RPM Delivery Years 2014/2015, 2015/2016, and 2016/2017

A. This transition provision applies only with respect to Generation Capacity Resources with existing capacity commitments for the 2014/2015, 2015/2016, or 2016/2017 Delivery Years that experience reductions in verified installed capacity available for sale as a direct result of revised generating unit capability verification test procedures effective with the summer 2014 capability tests, as set forth in the PJM Manuals. A Generation Capacity Resource meeting the description of the preceding sentence, and the Capacity Market Seller of such a resource, are hereafter in this section 5.14B referred to as an “Affected Resource” and an “Affected Resource Owner,” respectively.

B. For each of its Affected Resources, an Affected Resource Owner is required to provide documentation to the Office of the Interconnection sufficient to show a reduction in installed capacity value as a direct result of the revised capability test procedures. Upon acceptance by the Office of the Interconnection, the Affected Resource's installed capacity value will be updated in the eRPM system to reflect the reduction, and the Affected Resource's Capacity Interconnection Rights value will be updated to reflect the reduction, effective June 1, 2014. The reduction's impact on the Affected Resource's existing capacity commitments for the 2014/2015 Delivery Year will be determined in Unforced Capacity terms, using the final EFORd value established by the Office of the Interconnection for the 2014/2015 Delivery Year as applied to the Third Incremental Auction for the 2014/2015 Delivery Year, to convert installed capacity to Unforced Capacity. The reduction's impact on the Affected Resource's existing capacity commitments for each of the 2015/2016 and 2016/2017 Delivery Years will be determined in Unforced Capacity terms, using the EFORd value from each Sell Offer in each applicable RPM Auction, applied on a pro-rata basis, to convert installed capacity to Unforced Capacity. The Unforced Capacity impact for each Delivery Year represents the Affected Resource's capacity commitment shortfall, resulting wholly and directly from the revised capability test procedures, for which the Affected Resource Owner is subject to a Capacity Resource Deficiency Charge for the Delivery Year, as described in section 8 of this Attachment DD, unless the Affected Resource Owner (i) provides replacement Unforced Capacity, as described in section 8.1 of this Attachment DD, prior to the start of the Delivery Year to resolve the Affected Resource's total capacity commitment shortfall; or (ii) requests relief from Capacity Resource Deficiency Charges that result wholly and directly from the revised capability test procedures by electing the transition mechanism described in this section 5.14B ("Transition Mechanism").

C. Under the Transition Mechanism, an Affected Resource Owner may elect to have the Unforced Capacity commitments for all of its Affected Resources reduced for the 2014/2015, 2015/2016, or 2016/2017 Delivery Years to eliminate the capacity commitment shortfalls, across all of its Affected Resources, that result wholly and directly from the revised capability test procedures, and for which the Affected Resource Owner otherwise would be subject to Capacity Resource Deficiency Charges for the Delivery Year. In electing this option, the Affected Resource Owner relinquishes RPM Auction Credits associated with the reductions in Unforced Capacity commitments for all of its Affected Resources for the Delivery Year, and Locational Reliability Charges as described in section 5.14(e) of this Attachment DD are adjusted accordingly. Affected Resource Owners wishing to elect the Transition Mechanism for the 2015/2016 Delivery Year must notify the Office of the Interconnection by May 30, 2014. Affected Resource Owners wishing to elect the Transition Mechanism for the 2016/2017 Delivery Year must notify the Office of the Interconnection by July 25, 2014.

D. The Office of the Interconnection will offset the total reduction (across all Affected Resources and Affected Resource Owners) in Unforced Capacity commitments associated with the Transition Mechanism for the 2015/2016 and 2016/2017 Delivery Years by applying corresponding adjustments to the quantity of Buy Bid or Sell Offer activity in the upcoming Incremental Auctions for each of those Delivery Years, as described in sections 5.12(b)(ii) and 5.12(b)(iii) of this Attachment DD.

E. By electing the Transition Mechanism, an Affected Resource Owner may receive relief from applicable Capacity Resource Deficiency Charges for the 2014/2015, 2015/2016, or 2016/2017 Delivery Years, and a Locational UCAP Seller that sells Locational UCAP based on an Affected Resource owned by the Affected Resource Owner may receive relief from applicable Capacity Resource Deficiency Charges for the 2014/2015 Delivery Year, to the extent that the Affected Resource Owner demonstrates, to the satisfaction of the Office of the Interconnection, that an inability to deliver the amount of Unforced Capacity previously committed for the 2014/2015, 2015/2016, or 2016/2017 Delivery Years is due to a reduction in verified installed capacity available for sale as a direct result of revised generating unit capability verification test procedures effective with the summer 2014 capability tests, as set forth in the PJM Manuals; provided, however, that the Affected Resource Owner must provide the Office of the Interconnection with all information deemed necessary by the Office of the Interconnection to assess the merits of the request for relief.

5.14C Demand Response Operational Resource Flexibility Transition Provision for RPM Delivery Years 2015/2016 and 2016/2017

A. This transition provision applies only to Demand Resources for which a Curtailment Service Provider has existing RPM commitments for the 2015/2016 or 2016/2017 Delivery Years (alternatively referred to in this section 5.14C as "Applicable Delivery Years" and each an "Applicable Delivery Year") that (i) cannot satisfy the 30-minute notification requirement as described in Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA; (ii) are not excepted from the 30-minute notification requirement as described in Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA; and (iii) cleared in the Base Residual Auction or First Incremental Auction for the 2015/2016 Delivery Year, or cleared in the Base Residual Auction for the 2016/2017 Delivery Year. A Demand Resource meeting these criteria and the Curtailment Service Provider of such a resource are hereafter in this section 5.14C referred to as an "Affected Demand Resource" and an "Affected Curtailment Service Provider," respectively.

B. For this section 5.14C to apply to an Affected Demand Resource, the Affected Curtailment Service Provider must notify the Office of the Interconnection in writing, with regard to the following information by the applicable deadline:

i) For each applicable Affected Demand Resource: the number of cleared megawatts of Unforced Capacity for the Applicable Delivery Year by end-use customer site that the Affected Curtailment Service Provider cannot deliver, calculated based on the most current information available to the Affected Curtailment Service Provider; the end-use customer name; electric distribution company's account number for the end-use customer; address of end-use customer; type of Demand Resource (i.e., Limited DR, Annual DR, Extended Summer DR); the Zone or sub-Zone in which the end-use customer is located; and, a detailed description of why the end-use customer cannot comply with the 30-minute notification requirement or qualify for one of the exceptions to the 30-minute notification requirement provided in Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA.

ii) If applicable, a detailed analysis that quantifies the amount of cleared megawatts of Unforced Capacity for the Applicable Delivery Year for prospective customer sales that could not be contracted by the Affected Curtailment Service Provider because of the 30-minute notification requirement provided in Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA that the Affected Curtailment

Service Provider cannot deliver, by type of Demand Resource (i.e. Limited DR, Annual DR, Extended Summer DR) and by Zone and sub-Zone, as applicable. The analysis should include the amount of Unforced Capacity expected from prospective customer sales for each Applicable Delivery Year and must include supporting detail to substantiate the difference in reduced sales expectations. The Affected Curtailment Service Provider should maintain records to support its analysis.

1. For the 2015/2016 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the Third Incremental Auction for the 2015/2016 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision may not sell or offer to sell megawatts in the modeled LDA or sub-LDA where an Affected Demand Resource is located in the Third Incremental Auction for the 2015/2016 Delivery Year.

2. For the 2016/2017 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the Second Incremental Auction for the 2016/2017 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision may not sell or offer to sell megawatts in the modeled LDA or sub-LDA where an Affected Demand Resource is located in the Second or Third Incremental Auctions for the 2016/2017 Delivery Year.

3. For the 2016/2017 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the Third Incremental Auction for the 2016/2017 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision must not have sold or offered to sell megawatts in the modeled LDA or sub-LDA where an Affected Demand Resource is located in the Second Incremental Auction for the 2016/2017 Delivery Year, and may not sell or offer to sell megawatts in the modeled LDA or sub-LDA where an Affected Demand Resource is located in the Third Incremental Auction for the 2016/2017 Delivery Year.

C. For the Third Incremental Auction for the 2015/2016 Delivery Year and the First, Second, and Third Incremental Auctions for the 2016/2017 Delivery Year, the Office of the Interconnection shall publish aggregate information on the undeliverable megawatts declared under this transition provision (hereafter, “non-viable megawatts”), by type of Demand Resource and by Zone or sub-Zone, concurrently with its posting of planning parameters for the applicable Scheduled Incremental Auction. Non-viable megawatts for a Scheduled Incremental Auction for an Applicable Delivery Year represent those megawatts meeting the criteria of subsection A above and declared in accordance with subsection B above. Prior to each Third Incremental Auction for an Applicable Delivery Year, the Office of the Interconnection shall apply adjustments equal to the declared non-viable megawatt quantity to the quantity of Buy Bid or Sell Offer activity in the upcoming Scheduled Incremental Auctions for the Applicable Delivery Year, as described in sections 5.12(b)(ii) and 5.12(b)(iii) of this Attachment DD. Prior to the Second Incremental Auction for the 2016/2017 Delivery Year, the Office of the Interconnection shall adjust the recalculated PJM Region Reliability Requirement and recalculated LDA Reliability Requirements, as described in section 5.4(c) of this Attachment DD, by the applicable quantity of declared non-viable megawatts, and shall update the PJM Region Reliability Requirement and each LDA Reliability Requirement for such Second Incremental Auction only if the combined change of the applicable adjustment and applicable recalculation is greater than or equal to the lessor of (i) 500 megawatts or (ii) one percent of the prior PJM Region Reliability Requirement or one percent of the prior LDA Reliability Requirement, as applicable.

D. Prior to the start of each Applicable Delivery Year, the Office of the Interconnection shall reduce, by type of Demand Resource and by Zone or sub-Zone, the capacity commitment of each Affected Curtailment Service Provider that utilizes this transition provision for the Applicable Delivery Year based on the non-viable megawatts declared by the Affected Curtailment Service Provider under this transition provision. If the Affected Curtailment Service Provider cleared megawatts from multiple Affected Demand Resources of the same type and Zone or sub-Zone, or cleared megawatts in multiple RPM Auctions for the Applicable Delivery Year, the Office of the Interconnection shall allocate the reduction in capacity commitment by type of Demand Resource and by Zone or sub-Zone across the applicable Affected Demand Resources and relevant RPM Auctions. Such allocation shall be performed on a pro-rata basis, based on megawatts cleared by the Affected Demand Resources in the relevant RPM Auctions.

E. For each Applicable Delivery Year, an Affected Curtailment Service Provider that utilizes this transition provision for the Applicable Delivery Year relinquishes an Affected Demand Resource's RPM Auction Credits for the amount of capacity commitment reduction as determined under subsection D above. Locational Reliability Charges as described in section 5.14(e) of this Attachment DD are also adjusted accordingly.

5.14D Capacity Performance and Base Capacity Transition Provision for RPM Delivery Years 2016/2017 and 2017/2018

A. This transition provision applies only for procuring Capacity Performance Resources for the 2016/2017 and 2017/2018 Delivery Years.

B. For both the 2016/2017 and 2017/2018 Delivery Years, PJM will hold a Capacity Performance Transition Incremental Auction to procure Capacity Performance Resources.

1. For each Capacity Performance Transition Incremental Auction, the optimization algorithm shall consider:

- the target quantities of Capacity Performance Resources specified below;
- the Sell Offers submitted in such auction.

The Office of the Interconnection shall submit a Buy Bid based on the quantity of Capacity Performance Resources specified for that Delivery Year. For the 2016/2017 Delivery Year, the Office of the Interconnection shall submit a Buy Bid, at a price no higher than 0.5 times the Net CONE value for the PJM Region determined for the Base Residual Auction for that Delivery Year, for a quantity of Capacity Performance Resources equal to 60 percent of the updated Reliability Requirement for the PJM Region. For the 2017/2018 Delivery Year, the Office of the Interconnection shall submit a Buy Bid, at a price no higher than 0.6 times the Net CONE value for the PJM Region determined for the Base Residual Auction for that Delivery Year, for a quantity of Capacity Performance Resources equal to 70 percent of the updated Reliability Requirement for the PJM Region.

2. For each Capacity Performance Transition 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. For the 2016/2017 Delivery Year, the Capacity Resource Clearing Price for any Capacity Performance Transition Incremental Auction shall not exceed 0.5 times the Net CONE value for the PJM Region determined for the Base Residual Auction for that Delivery Year. For the 2017/2018 Delivery Year, the Capacity Resource Clearing Price for any Capacity Performance Transition Incremental Auction shall not exceed 0.6 times the Net CONE value for the PJM Region determined for the Base Residual Auction for that Delivery Year.

3. A Capacity Market Seller may offer any Capacity Resource that has not been committed in an FRR Capacity Plan, that qualifies as a Capacity Performance Resource under section 5.5A(a) and that (i) has not cleared an RPM Auction for that Delivery Year; or (ii) has cleared in an RPM Auction for that Delivery Year. A Capacity Market Seller may offer an external Generation Capacity Resource to the extent that such resource: (i) is reasonably expected, by the relevant Delivery Year, to meet all applicable requirements to be treated as equivalent to PJM Region internal generation that is not subject to NERC tagging as an interchange transaction; (ii) has long-term firm transmission service confirmed on the complete transmission path from such resource into PJM; and (iii) is, by written commitment of the Capacity Market Seller, subject to the same obligations imposed on Generation Capacity Resources located in the PJM Region by section 6.6 of Attachment DD of the PJM Tariff to offer their capacity into RPM Auctions.

4. Capacity Resources that already cleared an RPM Auction for a Delivery Year, retain the capacity obligations for that Delivery Year, and clear in a Capacity Performance Transition Incremental Auction for the same Delivery Year shall: (i) receive a payment equal to the Capacity Resource Clearing Price as established in that Capacity Performance Transition Incremental Auction; and (ii) not be eligible to receive a payment for clearing in any prior RPM Auction for that Delivery Year.

D. All Capacity Performance Resources that clear in a Capacity Performance Transition Incremental Auction will be subject to the Non-Performance Charge set forth in section 10A.

5.14E Demand Response Legacy Direct Load Control Transition Provision for RPM Delivery Years 2016/2017, 2017/2018, and 2018/2019

A. This transition provision applies only to Demand Resources for which a Curtailment Service Provider has existing RPM commitments for the 2016/2017, 2017/2018, or 2018/2019 Delivery Years (alternatively referred to in this section 5.14E as “Applicable Delivery Years” and each an “Applicable Delivery Year”) that (i) qualified as Legacy Direct Load Control before June 1, 2016 as described in Section G of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA; (ii) cannot meet the requirements for using statistical sampling for residential non-interval metered customers as described in Section K of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA; and (iii) cleared in the

Base Residual Auction or First Incremental Auction for the 2016/2017 Delivery Year, cleared in the Base Residual Auction for the 2017/2018 Delivery Year, or cleared in the Base Residual Auction for the 2018/2019 Delivery Year. A Demand Resource meeting these criteria and the Curtailment Service Provider of such a resource are hereafter in this section 5.14E referred to as an "Affected Demand Resource" and an "Affected Curtailment Service Provider," respectively.

B. For this section 5.14E to apply to an Affected Demand Resource, the Affected Curtailment Service Provider must notify the Office of the Interconnection in writing, with regard to the following information, by the applicable deadline:

i) For each applicable Affected Demand Resource: the number of cleared megawatts of Unforced Capacity for the Applicable Delivery Year by end-use customer site that the Affected Curtailment Service Provider cannot deliver, calculated based on the most current information available to the Affected Curtailment Service Provider; electric distribution company's account number for the end-use customer; address of end-use customer; type of Demand Resource (i.e., Limited DR, Annual DR, Extended Summer DR); the Zone or sub-Zone in which the end-use customer is located; and, a detailed description of why the endues customer cannot comply with statistical sampling for residential non-interval metered customers requirement as described in Section K of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA.

ii) If applicable, a detailed analysis that quantifies the amount of cleared megawatts of Unforced Capacity for the Applicable Delivery Year for prospective customer sales that could not be contracted by the Affected Curtailment Service Provider because of the statistical sampling for residential non-interval metered customers requirement as described in Section K of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA that the Affected Curtailment Service Provider cannot deliver, by type of Demand Resource (i.e. Limited DR, Annual DR, Extended Summer DR) and by Zone and sub-Zone, as applicable. The analysis should include the amount of Unforced Capacity expected from prospective customer sales for each Applicable Delivery Year and must include supporting detail to substantiate the difference in reduced sales expectations. The Affected Curtailment Service Provider should maintain records to support its analysis.

1. For the 2016/2017 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the Second and/or Third Incremental Auction for the 2016/2017 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision may not sell or offer to sell megawatts in the matching LDA or sub-LDA where an Affected Demand Resource is located in the Second or Third Incremental Auction for the 2016/2017 Delivery Year.

2. For the 2017/2018 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the First, Second and/or Third Incremental Auction for the 2017/2018 Delivery Year. Such

Affected Curtailment Service Provider that utilizes this transition provision may not sell or offer to sell megawatts in the matching LDA or sub-LDA where an Affected Demand Resource is located in the First, Second or Third Incremental Auctions for the 2017/2018 Delivery Year.

3. For the 2018/2019 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the First, Second and/or Third Incremental Auction for the 2018/2019 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision may not sell or offer to sell megawatts in the matching LDA or sub-LDA where an Affected Demand Resource is located in the First, Second or Third Incremental Auctions for the 2018/2019 Delivery Year.

C. For the Second and Third Incremental Auction for the 2016/2017 Delivery Year, the First, Second, and Third Incremental Auctions for the 2017/2018 Delivery Year, and the First, Second, and Third Incremental Auctions for the 2018/2019 Delivery Year, the Office of the Interconnection shall publish aggregate information on the undeliverable megawatts declared under this transition provision (hereafter, "non-viable megawatts"), by type of Demand Resource and by Zone or sub-Zone, concurrently with its posting of planning parameters for the applicable Scheduled Incremental Auction. Non-viable megawatts for a Scheduled Incremental Auction for an Applicable Delivery Year represent those megawatts meeting the criteria of subsection A above and declared in accordance with subsection B above. Prior to each Scheduled Incremental Auction for an Applicable Delivery Year, the Office of the Interconnection shall apply adjustments equal to the declared non-viable megawatt quantity to the quantity of Buy Bid or Sell Offer activity in the upcoming Scheduled Incremental Auctions for the Applicable Delivery Year, as described in sections 5.12(b)(ii) and 5.12(b)(iii) of this Attachment DD. Prior to the Second Incremental Auction for the 2016/2017 Delivery Year, the First and Second Incremental Auction for the 2017/2018 Delivery Year, and the First and Second Incremental Auction for the 2018/2019 Delivery Year, the Office of the Interconnection shall adjust the recalculated PJM Region Reliability Requirement and recalculated LDA Reliability Requirements, as described in section 5.4(c) of this Attachment DD, by the applicable quantity of declared non-viable megawatts, and shall update the PJM Region Reliability Requirement and each LDA Reliability Requirement for such Incremental Auction only if the combined change of the applicable adjustment and applicable recalculation is greater than or equal to the lessor of (i) 500 megawatts or (ii) one percent of the prior PJM Region Reliability Requirement or one percent of the prior LDA Reliability Requirement, as applicable.

D. Prior to the start of each Applicable Delivery Year, the Office of the Interconnection shall reduce, by type of Demand Resource and by Zone or sub-Zone, the capacity commitment of each Affected Curtailment Service Provider that utilizes this transition provision for the Applicable Delivery Year based on the non-viable megawatts declared by the Affected Curtailment Service Provider under this transition provision. If the Affected Curtailment Service Provider cleared megawatts from multiple Affected Demand Resources of the same type and Zone or sub-Zone, or cleared MWs in multiple RPM Auctions for the Applicable Delivery Year, the Office of the Interconnection shall allocate the reduction in capacity commitment by type of Demand Resource and by Zone or sub-Zone across the applicable Affected Demand Resources and relevant RPM Auctions. Such allocation shall be performed on a pro-rata basis, based on megawatts cleared by the Affected Demand Resources in the relevant RPM Auctions.

E. For each Applicable Delivery Year, an Affected Curtailment Service Provider that utilizes this transition provision for the Applicable Delivery Year relinquishes an Affected Demand Resource's RPM Auction credits for the amount of capacity commitment reduction as determined under subsection D above. Locational Reliability Charges as described in section 5.14(e) of this Attachment DD are also adjusted accordingly.

6. MARKET POWER MITIGATION

6.1 Applicability

The provisions of the Market Monitoring Plan (in Tariff, Attachment M and Attachment - M Appendix and this section 6) shall apply to the Reliability Pricing Model Auctions.

6.2 Process

(a) [Reserved for Future Use]

(b) In accordance with the schedule specified in the PJM Manuals, following PJM's conduct of a Base Residual Auction or Incremental Auction pursuant to Tariff, Attachment DD, section 5.12, but prior to the Office of the Interconnection's final determination of clearing prices and charges pursuant to Tariff, Attachment DD, section 5.14, the Office of the Interconnection shall: (i) apply the Market Structure Test to any LDA having a Locational Price Adder greater than zero and to the entire PJM region; (ii) apply Market Seller Offer Caps, if required under this section 6; and (iii) recompute the optimization algorithm to clear the auction with the Market Seller Offer Caps in place.

(c) Within seven days after the deadline for submission of Sell Offers in a Base Residual Auction or Incremental Auction, the Office of the Interconnection shall file with FERC a report of any determination made pursuant to Tariff, Attachment DD, section 5.14(h), Tariff, Attachment DD, section 6.5(a)(ii), or Tariff, Attachment DD, section 6.7(c) identified in such sections as subject to the procedures of this section. Such report shall list each such determination, the information considered in making each such determination, and an explanation of each such determination. Any entity that objects to any such determination may file a written objection with FERC no later than seven days after the filing of the report. Any such objection must not merely allege that the determination was in error, and must provide support for the objection, demonstrating that the determination overlooked or failed to consider relevant evidence. In the event that no objection is filed, the determination shall be final. In the event that an objection is filed, FERC shall issue any decision modifying the determination no later than 60 days after the filing of such report; otherwise, the determination shall be final. Final auction results shall reflect any decision made by FERC regarding the report.

6.3 Market Structure Test

(a) [Reserved for Future Use]

(b) Market Structure Test.

A constrained LDA or the PJM Region shall fail the Market Structure Test, and mitigation shall be applied to all jointly pivotal suppliers (including all Affiliates of such suppliers, and all third-party supply in the relevant LDA controlled by such suppliers by contract), if, as to the Sell Offers that comprise the incremental supply determined pursuant to section 6.3(c) below that are based on Generation Capacity Resources, there are not more than three jointly pivotal suppliers. The Office of the Interconnection shall apply the Market Structure Test. The Office of the Interconnection shall confirm the results of the Market Structure Test with the Market Monitoring Unit.

(c) Determination of Incremental Supply

In applying the Market Structure Test, the Office of the Interconnection shall consider all (i) incremental supply (provided, however, that the Office of the Interconnection shall consider only such supply available from Generation Capacity Resources) available to solve the constraint applicable to a constrained LDA offered at less than or equal to 150% of the cost-based clearing price; or (ii) supply for the PJM Region, offered at less than or equal to 150% of the cost-based clearing price, provided that supply in this section includes only the lower of cost-based or market-based offers from Generation Capacity Resources. Cost-based clearing prices are the prices resulting from the RPM auction algorithm using the lower of cost-based or price-based offers for all Capacity Resources.

6.4 Market Seller Offer Caps

(a) The Market Seller Offer Cap, stated in dollars per MW/day of unforced capacity, applicable to price-quantity offers within the Base Offer Segment for an Existing Generation Capacity Resource shall be the Avoidable Cost Rate for such resource, less the Projected PJM Market Revenues for such resource, stated in dollars per MW/day of unforced capacity, provided, however, that the default Market Seller Offer Cap for any Capacity Performance Resource shall be the product of (the Net Cost of New Entry applicable for the Delivery Year and Locational Deliverability Area for which such Capacity Performance Resource is offered times the average of the Balancing Ratios in the three consecutive calendar years (during the Performance Assessment Intervals in such calendar years) that precede the Base Residual Auction for such Delivery Year), however, for the Base Residual Auction for the 2021/2022 Delivery Year, the Balancing Ratio used in the determination of the default Market Seller Offer Cap shall be 78.5 percent, and provided further that the submission of a Sell Offer with an Offer Price at or below the revised Market Seller Offer Cap permitted under this proviso shall not, in and of itself, be deemed an exercise of market power in the RPM market; nor shall a Sell Offer with an Offer Price equal to the applicable MOPR Floor Offer Price, in and of itself, be deemed an exercise of market power in the RPM market. Notwithstanding the previous sentence, a Capacity Market Seller may seek and obtain a Market Seller Offer Cap for a Capacity Performance Resource that exceeds the revised Market Seller Offer Cap permitted under the prior sentence, if it supports and obtains approval of such alternative offer cap pursuant to the procedures and standards of subsection (b) of this section 6.4. A Capacity Market Seller may not use the Capacity Performance default Market Seller Offer Cap, and also seek to include any one or more categories of the Avoidable Cost Rate defined in Tariff, Attachment DD, section 6.8 below. The Market Seller Offer Cap for an Existing Generation Capacity Resource shall be the Opportunity Cost for such resource, if applicable, as determined in accordance with Tariff, Attachment DD, section 6.7. Nothing herein shall preclude any Capacity Market Seller and the Market Monitoring Unit from agreeing to, nor require either such entity to agree to, an alternative market seller offer cap determined on a mutually agreeable basis. Any such alternative offer cap shall be filed with the Commission for its approval. This provision is duplicated in Tariff, Attachment M-Appendix, section II.E.3.

(b) For each Existing Generation Capacity Resource, a potential Capacity Market Seller must provide to the Market Monitoring Unit and the Office of the Interconnection data and documentation required under section 6.7 below to establish the level of the Market Seller Offer Cap applicable to each resource by no later than one hundred twenty (120) days prior to the commencement of the offer period for the applicable RPM Auction. The Capacity Market Seller must promptly address any concerns identified by the Market Monitoring Unit regarding the data and documentation provided, review the Market Seller Offer Cap proposed by the Market Monitoring Unit, and attempt to reach agreement with the Market Monitoring Unit on the level of the Market Seller Offer Cap by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction. The Capacity Market Seller shall notify the Market Monitoring Unit in writing, with a copy to the Office of the Interconnection, whether an agreement with the Market Monitoring Unit has been reached or, if no agreement has been reached, specifying the level of Market Seller Offer Cap to which it commits by no later than eighty (80) days prior to the commencement of the offer period for the applicable RPM Auction. The Office of the Interconnection shall review the data submitted by the Capacity Market Seller, make a determination whether to accept or reject the requested unit-specific Market Seller Offer Cap, and notify the Capacity Market Seller and the Market Monitoring Unit of its determination in writing, by no later than sixty-five (65) days prior to the commencement of the offer period for the applicable RPM Auction. If the Market Monitoring Unit does not provide its determination to the Capacity Market Seller and the Office of the Interconnection by the specified deadline, by no later than sixty-five (65) days prior to the commencement of the offer period for the applicable RPM Auction the Office of the Interconnection will make the determination of the level of the Market Seller Offer Cap, which shall be deemed to be final. If the Capacity Market Seller does not notify the Market Monitoring Unit and the Office of the Interconnection of the Market Seller Offer Cap it desires to utilize by no later than eighty (80) days prior to the commencement of the offer period for the applicable RPM Auction, it shall be required to utilize a Market Seller Offer Cap determined using the applicable default Avoidable Cost Rate specified in section 6.7(c) below.

(c) Nothing in this section precludes the Capacity Market Seller from filing a petition with FERC seeking a determination of whether the Sell Offer complies with the requirements of the Tariff.

(d) For any Third Incremental Auction for Delivery Years through the 2017/2018 Delivery Year, the Market Seller Offer Cap for an Existing Generation Capacity Resource shall be determined pursuant to subsection (a) of this Section 6.4, or if elected by the Capacity Market Seller, shall be equal to 1.1 times the Capacity Resource Clearing Price in the Base Residual Auction for the relevant LDA and Delivery Year. For any Third Incremental Auction for the 2018/2019 or 2019/2020 Delivery Years, the Market Seller Offer Cap for an Existing Generation Capacity Resource offering as a Base Capacity resource shall be determined pursuant to subsection (a) of this Section 6.4, or if elected by the Capacity Market Seller, shall be equal to 1.1 times the Capacity Resource Clearing Price in the Base Residual Auction for the relevant LDA and Delivery Year. For any Third Incremental Auction for the 2018/2019 Delivery Year or any subsequent Delivery Year, the Market Seller Offer Cap for an Existing Generation Capacity Resource offering as a Capacity Performance Resource shall be determined pursuant to subsection (a) of this Section 6.4, or if elected by the Capacity Market Seller, shall be equal to the greater of the Net Cost of New Entry times the Balancing Ratio for the relevant LDA and Delivery Year or 1.1 times the

Capacity Resource Clearing Price in the Base Residual Auction for the relevant LDA and Delivery Year.

6.5 Mitigation

The Office of the Interconnection shall apply market power mitigation measures in any Base Residual Auction or Incremental Auction for any LDA, Unconstrained LDA Group, or the PJM Region that fails the Market Structure Test.

(a) Mitigation for Generation Capacity Resources.

i) Existing Generation Capacity Resource

Mitigation will be applied on a unit-specific basis and only if the Sell Offer of Unforced Capacity from an Existing Generation Capacity Resource: (1) is greater than the Market Seller Offer Cap applicable to such resource; and (2) would, absent mitigation, increase the Capacity Resource Clearing Price in the relevant auction. If such conditions are met, such Sell Offer shall be set equal to the higher of the applicable Market Seller Offer Cap or the applicable MOPR Floor Offer Price.

ii) Planned Generation Capacity Resources

(A) Sell Offers based on Planned Generation Capacity Resources (including External Planned Generation Capacity Resources) shall be presumed to be competitive and shall not be subject to market power mitigation in any Base Residual Auction or Incremental Auction for which such resource qualifies as a Planned Generation Capacity Resource, but any such Sell Offer shall be rejected if it meets the criteria set forth in subsection (C) below, unless the Capacity Market Seller obtains approval from FERC for use of such offer prior to the close of the offer period for the applicable RPM Auction.

(B) Sell Offers based on Planned Generation Capacity Resources (including Planned External Generation Capacity Resources) shall be deemed competitive and not be subject to mitigation if: (1) collectively all such Sell Offers provide Unforced Capacity in an amount equal to or greater than two times the incremental quantity of new entry required to meet the LDA Reliability Requirement; and (2) at least two unaffiliated suppliers have submitted Sell Offers for Planned Generation Capacity Resources in such LDA. Notwithstanding the foregoing, any Capacity Market Seller, together with Affiliates, whose Sell Offers based on Planned Generation Capacity Resources in that modeled LDA are pivotal, shall be subject to mitigation.

(C) Where the two conditions stated in subsection (B) above are not met, or the Sell Offer is pivotal, the Sell Offer shall be rejected if it exceeds the higher of the applicable MOPR Floor Offer Price, if applicable, or 140 percent of: 1) the average of location-adjusted Sell Offers for Planned

Generation Capacity Resources from the same asset class as such Sell Offer, submitted (and not rejected) (Asset-Class New Plant Offers) for such Delivery Year; or 2) if there are no Asset-Class New Plant Offers for such Delivery Year, the average of Asset-Class New Plant Offers for all prior Delivery Years; or 3) if there are no Asset-Class New Plant Offers for any prior Delivery Year, the Net CONE applicable for such Delivery Year in the LDA for which such Sell Offer was submitted. For purposes of this section, asset classes shall be as stated in section 6.7(c) below as effective for such Delivery Year, and Asset-Class New Plant Offers shall be location-adjusted by the ratio between the Net CONE effective for such Delivery Year for the LDA in which the Sell Offer subject to this section was submitted and the average, weighted by installed capacity, of the Net CONEs for all LDAs in which the units underlying such Asset Class New Plant Offers are located. Following the conduct of the applicable auction and before the final determination of clearing prices, in accordance with Section 6.2(b) above, each Capacity Market Seller whose Sell Offer is so rejected shall be notified in writing by the Office of the Interconnection by no later than one (1) Business Day after the close of the offer period for the applicable RPM Auction and allowed an opportunity to submit a revised Sell Offer that does not exceed such threshold within one (1) Business Day of the Office of the Interconnection's rejection of such Sell Offer. If such revised Sell Offer is accepted by the Office of the Interconnection, the Office of the Interconnection then shall clear the auction with such revised Sell Offer in place. Pursuant to Tariff, Attachment M-Appendix, Section II.F, the Market Monitoring Unit shall notify in writing each Capacity Market Seller whose Sell Offer has been determined to be non-competitive and subject to mitigation, with a copy to the Office of the Interconnection, by no later than one (1) Business Day after the close of the offer period for the applicable RPM Auction.

(b) Mitigation for Demand Resources

The Market Seller Offer Cap shall not be applied to Sell Offers of Demand Resources or Energy Efficiency Resources.

6.6 Offer Requirement for Capacity Resources

(a) To avoid application of subsection (h) below, all of the installed capacity of all Existing Generation Capacity Resources located in the PJM Region shall be offered by the Capacity Market Seller that owns or controls all or part of such resource (which may include submission as Self-Supply) in all RPM Auctions for each Delivery Year, less any amount determined by the Office of the Interconnection to be eligible for an exception to this RPM must-offer requirement, where installed capacity is determined as of the date on which bidding commences for each RPM Auction pursuant to Tariff, Attachment DD, section 5.6.6. The Unforced Capacity of such resources is determined using the EFORd value that is submitted by the Capacity Market Seller in its Sell Offer, which shall not exceed the maximum EFORd for that resource as defined in section 6.6(b). If a resource should be included on the list of Existing

Generation Capacity Resources subject to the RPM must-offer requirement that is maintained by the Market Monitoring Unit pursuant to Tariff, Attachment M-Appendix, section II.C.1, but is omitted therefrom whether by mistake of the Market Monitoring Unit or failure of the Capacity Market Seller that owns or controls all or part of such resource to provide information about the resource to the Market Monitoring Unit, this shall not excuse such resource from the RPM must-offer requirement.

(b) For each Existing Generation Capacity Resource, a potential Capacity Market Seller must timely provide to the Market Monitoring Unit and the Office of the Interconnection all data and documentation required under this section 6.6 to establish the maximum EFORd applicable to each resource in accordance with standards and procedures specified in the PJM Manuals. The maximum EFORd that may be used in a Sell Offer for RPM Auctions held prior to the date on which the final EFORds used for a Delivery Year are posted, is the greater of (i) the average EFORd for the five consecutive years ending on the September 30 that last precedes the Base Residual Auction, or (ii) the EFORd for the 12 months ending on the September 30 that last precedes the Base Residual Auction.

Notwithstanding the foregoing, a Capacity Market Seller may request an alternate maximum EFORd for Sell Offers submitted in such auctions if it has a documented, known reason that would result in an increase in its EFORd, by submitting a written request to the Market Monitoring Unit and Office of the Interconnection, along with data and documentation required to support the request for an alternate maximum EFORd, by no later one hundred twenty (120) days prior to the commencement of the offer period for the Base Residual Auction for the applicable Delivery Year. The Capacity Market Seller must address any concerns identified by the Market Monitoring Unit and/or the Office of the Interconnection regarding the data and documentation provided and attempt to reach agreement with the Market Monitoring Unit on the level of the alternate maximum EFORd by no later than ninety (90) days prior to the commencement of the offer period for the Base Residual Auction for the applicable Delivery Year. As further described in Tariff, Attachment M-Appendix, section II.C, the Market Monitoring Unit shall notify the Capacity Market Seller and the Office of the Interconnection in writing of its determination of the requested alternate maximum EFORd by no later than ninety (90) days prior to the commencement of the offer period for the Base Residual Auction for the applicable Delivery Year. By no later than eighty (80) days prior to the commencement of the offer period for the Base Residual Auction for the applicable Delivery Year, the Capacity Market Seller shall notify the Office of the Interconnection and the Market Monitoring Unit in writing whether it agrees with the Market Monitoring Unit on the alternate maximum EFORd or, if no agreement has been reached, specifying the level of alternate maximum EFORd to which it commits. If a Capacity Market Seller fails to request an alternate maximum EFORd prior to the specified deadlines, the maximum EFORd for the applicable RPM Auction shall be deemed to be the default EFORd calculated pursuant to this section.

The maximum EFORd that may be used in a Sell Offer for Third Incremental Auction, and for Conditional Incremental Auctions held after the date on which the final EFORd used for a Delivery Year is posted, is the EFORd for the 12 months ending on the September 30 that last precedes the submission of such offers.

(c) [Reserved for Future Use]

(d) In the event that a Capacity Market Seller and the Market Monitoring Unit cannot agree on the maximum level of the alternate EFORd that may be used in a Sell Offer for RPM Auctions held prior to the date on which the final EFORds used for a Delivery Year are posted, the Office of the Interconnection shall make its own determination of the maximum level of the alternate EFORd based on the requirements of the Tariff and the PJM Manuals, per Tariff, Attachment DD, section 5.8, by no later than sixty-five (65) days prior to the commencement of the offer period for the Base Residual for the applicable Delivery Year, and shall notify the Capacity Market Seller and the Market Monitoring Unit in writing of such determination.

(e) Nothing in this section precludes the Capacity Market Seller from filing a petition with FERC seeking a determination of whether the EFORd complies with the requirements of the Tariff.

(f) Notwithstanding the foregoing, a Capacity Market Seller may submit an EFORd that it chooses for an RPM Auction held prior to the date on which the final EFORd used for a Delivery Year is posted, provided that (i) it has participated in good faith with the process described in this section 6.6 and in Tariff, Attachment M-Appendix, section II.C, (ii) the offer is no higher than the level defined in any agreement reached by the Capacity Market Seller and the Market Monitoring Unit that resulted from the foregoing process, and (iii) the offer is accepted by the Office of the Interconnection subject to the criteria set forth in the Tariff and the PJM Manuals.

(g) A Capacity Market Seller that owns or controls an existing generation resource in the PJM Region that is capable of qualifying as an Existing Generation Capacity Resource as of the date on which bidding commences for an RPM Auction may not avoid the rule in subsection (a) or be removed from Capacity Resource status by failing to qualify as a Generation Capacity Resource, or by attempting to remove a unit previously qualified as a Generation Capacity Resource from classification as a Capacity Resource for that RPM Auction. However, generation resource may qualify for an exception to the RPM must-offer requirement, as shown by appropriate documentation, if the Capacity Market Seller that owns or controls such resource demonstrates that it: (i) is reasonably expected to be physically unable to participate in the relevant Delivery Year; (ii) has a financially and physically firm commitment to an external sale of its capacity, or (iii) was interconnected to the Transmission System as an Energy Resource and not subsequently converted to a Capacity Resource.

In order to establish that a resource is reasonably expected to be physically unable to participate in the relevant auction as set forth in (i) above, the Capacity Market Seller must demonstrate that:

A. It has a documented plan in place to retire the resource prior to or during the Delivery Year, and has submitted a notice of Deactivation to the Office of the Interconnection consistent with Tariff, Part V, section 113.1, without regard to whether the Office of the Interconnection has requested the Capacity Market Seller to continue to operate the resource beyond its desired deactivation date in accordance with Tariff, Part V, section 113.2 for the purpose of maintaining the reliability of the PJM Transmission System and the Capacity Market Seller has agreed to do so;

B. Significant physical operational restrictions cause long term or permanent changes to the installed capacity value of the resource, or the resource is under major repair that will extend into the applicable Delivery Year, that will result in the imposition of RPM performance penalties pursuant to Tariff, Attachment DD;

C. The Capacity Market Seller is involved in an ongoing regulatory proceeding (e.g. – regarding potential environmental restrictions) specific to the resource and has received an order, decision, final rule, opinion or other final directive from the regulatory authority that will result in the retirement of the resource; or

D. A resource considered an Existing Generating Capacity Resource because it cleared an RPM Auction for a Delivery Year prior to the Delivery Year of the relevant auction, but which is not yet in service, is unable to achieve full commercial operation prior to the Delivery Year of the relevant auction. The Capacity Market Seller must submit to the Office of the Interconnection and the Market Monitoring Unit a written sworn, notarized statement of a corporate officer certifying that the resource will not be in full commercial operation prior to the referenced Delivery Year.

In order to establish that a resource has a financially and physically firm commitment to an external sale of its capacity as set forth in (ii) above, the Capacity Market Seller must demonstrate that it has entered into a unit-specific bilateral transaction for service to load located outside the PJM Region, by a demonstration that such resource is identified on a unit-specific basis as a network resource under the transmission tariff for the control area applicable to such external load, or by an equivalent demonstration of a financially and physically firm commitment to an external sale. The Capacity Market Seller additionally shall identify the megawatt amount, export zone, and time period (in days) of the export.

A Capacity Market Seller that seeks approval for an exception to the RPM must-offer requirement, for any reason other than the reason specified in Paragraph A above, shall first submit such request in writing, along with all supporting data and documentation, to the Market Monitoring Unit for evaluation, notifying the Office of the Interconnection by copy of the same, by no later than one hundred twenty (120) days prior to the commencement of the offer period for the applicable RPM Auction.

In order to obtain an exception to the RPM must-offer requirement for the reason specified in Paragraph A above, a Capacity Market Seller shall first submit a preliminary exception request in writing, along with supporting data and documentation indicating the reasons and conditions upon which the Capacity Market Seller is relying in its analysis of whether to retire such resource, to the Market Monitoring Unit for evaluation, notifying the Office of the Interconnection by copy of the same, by no later than (a) November 1, 2013 for the Base Residual Auction for the 2017/2018 Delivery Year, (b) the September 1 that last precedes the Base Residual Auction for the 2018/2019 and subsequent Delivery Years, and (c) two hundred forty (240) days prior to the commencement of the offer period for the applicable Incremental Auction. By no later than five (5) Business Days after receipt of any such preliminary exception requests, the Office of the Interconnection will post on its website a summary of the number of megawatts of Generation Capacity Resources for which it has received notification of preliminary exception requests, on an aggregate basis by Zone and Locational Deliverability Area that comprises a subset of a Zone, as specified in the PJM Manuals.

Thereafter, as applicable, such Capacity Market Seller shall by no later than (a) the December 1 that last precedes the Base Residual Auction for the applicable Delivery Year, or (b) one hundred twenty (120) days prior to the commencement of the offer period for the applicable Incremental Auction, either (a) notify the Office of the Interconnection and the Market Monitoring Unit in writing that it is withdrawing its preliminary exception request and explaining the changes to its analysis of whether to retire such resource that support its decision to withdraw, or (b) demonstrate that it has met the requirements specified under Paragraph A above. By no later than five (5) Business Days after receipt of such notification, the Office of the Interconnection will post on its website a revised summary of the number of megawatts of Generation Capacity Resources for which it has received requests for exceptions to the RPM must-offer requirement for the reason specified in Paragraph A above, on an aggregate basis by Zone and Locational Deliverability Area that comprises a subset of a Zone, as specified in the PJM Manuals.

A Capacity Market Seller that seeks to remove a Generation Capacity Resource from Capacity Resource status shall first submit a preliminary request in writing, along with supporting data and documentation indicating the reasons and conditions upon which the Capacity Market Seller is relying in its analysis of whether to remove the Capacity Resource status of such resource to the Market Monitoring Unit for evaluation, notifying the Office of the Interconnection by copy of the same, by no later than (a) the September 1 that last precedes the Base Residual Auction, and (b) two hundred forty (240) days prior to the commencement of the offer period for the applicable Incremental Auction. For the Base Residual Auction for the 2023/2024 Delivery Year, a Capacity Market Seller that seeks to remove a Generation Capacity Resource from Capacity Resource status shall first submit such preliminary request by no later than November 1, 2019. By no later than five (5) Business Days after receipt of any such preliminary requests, the Office of the Interconnection will post on its website a summary of the number of megawatts of Generation Capacity Resources for which it has received notification of preliminary requests, on an aggregate basis by Zone and Locational Deliverability Area that comprises a subset of a Zone, as specified in the PJM Manuals.

Thereafter, as applicable, such Capacity Market Seller shall, by no later than (a) the December 1 that last precedes the Base Residual Auction for the applicable Delivery Year, or (b) one hundred twenty (120) days prior to the commencement of the offer period for the applicable Incremental Auction, notify the Office of the Interconnection and the Market Monitoring Unit in writing that it is either (a) withdrawing its preliminary request and explaining the changes to its analysis that support its decision to withdraw, or (b) confirming its preliminary decision to remove the Generation Capacity Resource from Capacity Resource status. By no later than five (5) Business Days after receipt of such notification, the Office of the Interconnection will post on its website a revised summary of the number of megawatts of Generation Capacity Resources for which it has received requests to remove its Capacity Resource status, on an aggregate basis by Zone and Locational Deliverability Area that comprises a subset of a Zone, as specified in the PJM Manuals.

The Market Monitoring Unit shall analyze the effects of the proposed removal of a Generation Capacity Resource from Capacity Resource status with regard to potential market power issues and shall notify the Capacity Market Seller and the Office of the Interconnection in writing of its determination of the request to remove the Generation Capacity Resource from Capacity Resource status, and whether a market power issue has been identified, by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction. Such notice shall include the specific market power impact resulting from the proposed removal of the Generation Capacity Resource from Capacity Resource status, as well as an initial assessment of any steps that could be taken to mitigate the market power impact.

A Capacity Market Seller may only remove the Generation Capacity Resource from Capacity Resource status if (i) the Market Monitoring Unit has determined that the Generation Capacity Resource meets the applicable criteria set forth in Tariff, Attachment DD, sections 5.6.6 and this section 6.6 and the Office of the Interconnection agrees with this determination, or (ii) the Commission has issued an order terminating the Capacity Resource status of the resource, or (iii) it is required as set forth in Tariff, Attachment DD, section 6.6A(c). Nothing herein shall require a Market Seller to offer its resource into an RPM Auction prior to seeking to remove a resource from Capacity Resource status, subject to satisfaction of this section 6.6. A Generation Capacity Resource that is removed from Capacity Resource status shall no longer qualify as an Existing Generation Capacity Resource, and the Capacity Interconnection Rights associated with such facility shall be subject to termination in accordance with the rules described in Tariff, Part VI, section 230.3.3. The Office of the Interconnection shall amend the applicable Interconnection Service Agreement or wholesale market participation agreement to reflect any such removal of the Capacity Interconnection Rights, and shall report the amended agreement to the Commission in the same manner as the original (e.g., FERC filing or Electronic Quarterly Reports). The Office of the Interconnection shall file the amended agreement unexecuted if the Interconnection Customer or wholesale market participant does not sign the amended Interconnection Service Agreement or wholesale market participation agreement.

If the Capacity Market Seller disagrees with the Market Monitoring Unit's determination of its request to remove a resource from Capacity Resource status or its request for an exception to the RPM must-offer requirement, it must notify the Market Monitoring Unit in writing, with a copy to the Office of the Interconnection, of the same by no later than eighty (80) days prior to the commencement of the offer period for the applicable RPM Auction. After the Market Monitoring Unit has made its determination of whether a resource may be removed from Capacity Resource status, or whether the resource meets one of the exceptions thereto, and has notified the Capacity Market Seller and the Office of the Interconnection of the same pursuant to Tariff, Attachment M-Appendix, section II.C.4, the Office of the Interconnection shall approve or deny the request. The request shall be deemed to be approved by the Office of the Interconnection, consistent with the determination of the Market Monitoring Unit, unless the Office of the Interconnection notifies the Capacity Market Seller and Market Monitoring Unit, by no later than sixty-five (65) days prior to the date on which the offer period for the applicable RPM Auction commences, that the request is denied.

If the Market Monitoring Unit does not timely notify the Capacity Market Seller and the Office of the Interconnection of its determination of the request to remove a Generation Capacity Resource from Capacity Resource status or for an exception to the RPM must-offer requirement, the Office of the Interconnection shall make the determination whether the request shall be approved or denied, and will notify the Capacity Market Seller of its determination in writing, with a copy to the Market Monitoring Unit, by no later than sixty-five (65) days prior to the date on which the offer period for the applicable RPM Auction commences.

After the Market Monitoring Unit and the Office of the Interconnection have made their determinations of whether a resource meets the criteria to qualify for an exception to the RPM must-offer requirement, the Capacity Market Seller must notify the Market Monitoring Unit and the Office of the Interconnection whether it intends to exclude from its Sell Offer some or all of the subject capacity on the basis of an identified exception by no later than sixty-five (65) days prior to the date on which the offer period for the applicable RPM Auction commences. PJM does not make determinations of whether withholding of capacity constitutes market power. A Generation Capacity Resource that does not qualify for submission into an RPM Auction because it is not owned or controlled by the Capacity Market Seller for a full Delivery Year is not subject to the offer requirement hereunder; provided, however, that a Capacity Market Seller planning to transfer ownership or control of a Generation Capacity Resource during a Delivery Year pursuant to a sale or transfer agreement entered into after March 26, 2009 shall be required to satisfy the offer requirement hereunder for the entirety of such Delivery Year and may satisfy such requirement by providing for the assumption of this requirement by the transferee of ownership or control under such agreement.

If a Capacity Market Seller doesn’t timely seek to remove a Generation Capacity Resource from Capacity Resource status or timely submit a request for an exception to the RPM must-offer requirement, the Generation Capacity Resource shall only be removed from Capacity Resource status, and may only be approved for an exception to the RPM must-offer requirement, upon the Capacity Market Seller requesting and receiving an order from FERC, prior to the close of the offer period for the applicable RPM Auction, directing the Office of the Interconnection to remove the resource from Capacity Resource status and/or granting an exception to the RPM must-offer requirement or a waiver of the RPM must-offer requirement as to such resource.

(h) Any existing generation resource located in the PJM Region that satisfies the criteria in the definition of Existing Generation Capacity Resource as of the date on which bidding commences for the Base Residual Auction for a Delivery Year, that is not offered into such Base Residual Auction, and that does not meet any of the exceptions stated in the prior subsection (g): (i) may not participate in any subsequent Incremental Auctions conducted for such Delivery Year; (ii) shall not receive any payments under Tariff, Attachment DD, section 5.14 for such Delivery Year for the capacity of such Generation Capacity Resources; and (iii) shall not be permitted to satisfy any LSE’s Unforced Capacity Obligation, or any entity’s obligation to obtain the commitment of Capacity Resources, for such Delivery Year.

All generation resources located in the PJM Region that satisfy the criteria in the definition of Existing Generation Capacity Resource as of the date on which bidding commences for an Incremental Auction for a particular Delivery Year, but that did not satisfy such criteria as of the date that on which bidding commenced in the Base Residual Auction for that Delivery Year, that is not offered into that Incremental Auction, and that does not meet any of the exceptions stated in the prior subsection (g): (i) may not participate in any subsequent Incremental Auctions conducted for such Delivery Year; (ii) shall not receive any payments under Tariff, Attachment DD, section 5.14 for such Delivery Year for the capacity of such Generation Capacity Resources; and (iii) shall not be permitted to satisfy any LSE's Unforced Capacity Obligation, or any entity's obligation to obtain the commitment of Capacity Resources, for such Delivery Year.

All Existing Generation Capacity Resources that are offered into a Base Residual Auction or Incremental Auction for a particular Delivery Year but do not clear in such auction, that are not offered into each subsequent Incremental Auction, and that do not meet any of the exceptions stated in the prior subsection (g): (i) may not participate in any Incremental Auctions conducted for such Delivery Year subsequent to such failure to offer; (ii) shall not receive any payments under Tariff, Attachment DD, section 5.14 for such Delivery Year for the capacity of such Generation Capacity Resources; and (iii) shall not be permitted to satisfy any LSE's Unforced Capacity Obligation, or any entity's obligation to obtain the commitment of Capacity Resources, for such Delivery Year.

Any such Existing Generation Capacity Resources may also be subject to further action by the Market Monitoring Unit under the terms of Tariff, Attachment M and Tariff, Attachment M – Appendix.

(i) In addition to the remedies set forth in subsections (g) and (h) above, if the Market Monitoring Unit determines that one or more Capacity Market Sellers' failure to offer part or all of one or more existing generation resources, for which the Office of the Interconnection has not approved an exception to the RPM must-offer requirement, into an RPM Auction as required by this Section 6.6 would result in an increase of greater than five percent in any Zonal Capacity Price determined through such auction, and the Office of the Interconnection agrees with that determination, the Office of the Interconnection shall apply to FERC for an order, on an expedited basis, directing such Capacity Market Seller to participate in the relevant RPM Auction, or for other appropriate relief, and PJM will postpone clearing the auction pending FERC's decision on the matter. If the Office of the Interconnection disagrees with the Market Monitoring Unit's determination and does not apply to FERC for an order directing the Capacity Market Seller to participate in the auction or for other appropriate relief, the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and to seek appropriate relief.

6.6A Offer Requirement for Capacity Performance Resources

(a) For the 2018/2019 Delivery Year and subsequent Delivery Years, the installed capacity of every Generation Capacity Resource located in the PJM Region that is capable (or that reasonably can become capable) of qualifying as a Capacity Performance Resource shall be offered as a Capacity Performance Resource by the Capacity Market Seller that owns or controls all or part of such resource (which may include submission as Self-Supply) in all RPM Auctions for each such Delivery Year, less any amount determined by the Office of the Interconnection to be eligible for an exception to the Capacity Performance Resource must-offer requirement, where installed capacity is determined as of the date on which bidding commences for each RPM Auction pursuant to Tariff, Attachment DD, section 5.6.6.

(b) Determinations of EFORd and Unforced Capacity made under this section 6.6 as to a Generation Capacity Resource shall govern the offers required under this section as to the same Generation Capacity Resource.

(c) Exceptions to the requirement in subsection (a) shall be permitted only for a resource which the Capacity Market Seller demonstrates is reasonably expected to be physically incapable of satisfying the requirements of a Capacity Performance Resource. Intermittent Resources, Capacity Storage Resources, Demand Resources, and Energy Efficiency Resources shall not be required to offer as a Capacity Performance Resource, but shall not be precluded from being offered as a Capacity Performance Resource at a level that demonstrably satisfies such requirements. Exceptions shall be determined using the same timeline and procedures as specified in section 6.6.

Effective with the 2023/2024 Delivery Year, Capacity Market Sellers seeking an exception for a Base Residual Auction on the basis that a resource is incapable of meeting the Capacity Performance Resource requirement shall include a documented plan with the submission of their request showing the steps the Capacity Market Seller intends to pursue for the resource to become physically capable of satisfying the requirements of a Capacity Performance Resource. Such plan shall include (i) a timeline for design, permitting, procurement, and construction milestones, as applicable, where such timeline shall not exceed one Base Residual Auction exception, and (ii) evidence of corporate commitment (e.g., an SEC filing, a press release, or a letter from a duly authorized corporate officer indicating intent to make such investment). Periodic updates on the progress, shall be provided by the Capacity Market Seller to the Office of the Interconnection and the Market Monitoring Unit for their review by no later than (i) one hundred twenty (120) days prior to the commencement of the offer period for subsequent Incremental Auctions for the applicable Delivery Years, and (ii) the December 1 that last precedes subsequent Base Residual Auctions. The Capacity Market Seller shall also immediately notify the Office of the Interconnection and the Market Monitoring Unit of any material changes to the plan that may occur. Upon request by a Capacity Market Seller, a one year extension to the plan timeline shall be permissible only for delays not caused by the Capacity Market Seller, and that could not have been remedied through the exercise of due diligence by the Capacity Market Seller. In no event may an exception be requested by the Capacity Market Seller for more than two Base Residual Auctions.

Failure to submit a documented plan, or lack of good faith effort by a Capacity Market Seller to make an Existing Generation Capacity Resource physically capable of meeting the requirements of a Capacity Performance Resource in accordance with a documented plan, shall result in the removal of the resource’s Capacity Resource status effective with the first future Delivery Year for which the resource was granted an exception, no earlier than the 2023/2024 Delivery Year. The Office of the Interconnection shall amend the applicable Interconnection Service Agreement or wholesale market participation agreement to reflect any such removal of the Capacity Interconnection Rights, and shall report the amended agreement to the Commission in the same manner as the original (e.g. FERC Filing or Electronic Quarterly Reports). The Office of the Interconnection shall file the amended agreement unexecuted if the Interconnection Customer or wholesale market participant does not sign the amended Interconnection Service Agreement or wholesale market participation agreement. The required change in Capacity Resource status shall only apply to those Generation Capacity Resources that are shown to be physically incapable of satisfying the requirements of a Capacity Performance Resource.

(d) A resource not exempted or excepted under subsection (c) hereof that is capable of qualifying as a Capacity Performance Resource and does not offer into an RPM Auction as a

Capacity Performance Resource shall be subject to the same restrictions on subsequent offers, and other possible remedies, as specified in section 6.6.

6.7 Data Submission

(a) Potential participants in any PJM Reliability Pricing Model Auction shall submit, together with supporting documentation for each item, to the Market Monitoring Unit and the Office of the Interconnection no later than one hundred twenty (120) days prior to the posted date for the conduct of such auction, a list of owned or controlled generation resources by PJM transmission zone for the specified Delivery Year, including the amount of gross capacity, the EFORd and the net (unforced) capacity. A potential participant intending to offer any Capacity Performance Resource at or below the default Market Seller Offer Cap described in Tariff, Attachment DD, section 6.4(a) must provide the associated offer cap and the MW to which the offer cap applies.

(b) Except as provided in subsection (c) below, potential participants in any PJM Reliability Pricing Model Auction in any LDA or Unconstrained LDA Group that request a unit specific Avoidable Cost Rate shall, in addition, submit the following data, together with supporting documentation for each item, to the Market Monitoring Unit no later than one hundred twenty (120) days prior to the commencement of the offer period for such auction:

i. If the Capacity Market Seller intends to submit a non-zero price in its Sell Offer in any such auction, the Capacity Market Seller shall submit a calculation of the Avoidable Cost Rate and Projected PJM Market Revenues, as defined in subsection (d) below, together with detailed supporting documentation.

ii. If the Capacity Market Seller intends to submit a Sell Offer based on opportunity cost, the Capacity Market Seller shall also submit a calculation of Opportunity Cost, as defined in subsection (d), with detailed supporting documentation.

(c) Potential auction participants identified in subsection (b) above need not submit the data specified in that subsection for any Generation Capacity Resource:

i. that is in an Unconstrained LDA Group or, if this is the relevant market, the entire PJM Region, and is in a resource class identified in the table below as not likely to include the marginal price-setting resources in such auction; or

ii. for which the potential participant commits that any Sell Offer it submits as to such resource shall not include any price above: (1) the applicable default level identified below for the relevant resource class, less (2) the Projected PJM Market Revenues for such resource, as determined in accordance with this Tariff.

Nothing herein precludes the Market Monitoring Unit from requesting additional information from any potential auction participant as deemed necessary by the Market Monitoring Unit, including, without limitation, additional cost data on resources in a class that is not otherwise expected to include the marginal price setting resource as outlined in Tariff, Attachment M-Appendix, section II.G. Any Sell Offer submitted in any auction that is inconsistent with any agreement or commitment made pursuant to this subsection shall be rejected, and the Capacity Market Seller shall be required to resubmit a Sell Offer that complies with such agreement or commitment within one (1) Business Day of the Office of the Interconnection's rejection of such Sell Offer. If the Capacity Market Seller does not timely resubmit its Sell Offer, fails to request a unit-specific Avoidable Cost Rate by the specified deadline, or if the Office of the Interconnection determines that the information provided by the Capacity Market Seller in support of the requested unit-specific Avoidable Cost Rate or Sell Offer is incomplete, the Capacity Market Seller shall be deemed to have submitted a Sell Offer that complies with the commitments made under this subsection, with a default offer for the applicable class of resource or nearest comparable class of resource determined under this subsection (c)(ii). The obligation imposed under section 6.6(a) above shall not be satisfied unless and until the Capacity Market Seller submits (or is deemed to have submitted) a Sell Offer that conforms to its commitments made pursuant to this subsection or subject to the procedures set forth in section 6.4 above and Tariff, Attachment M-Appendix, section II.H.

The default retirement and mothball Avoidable Cost Rates ("ACR") referenced in this subsection (c)(ii) are as set forth in the tables below for the 2013/2014 Delivery Year through the 2016/2017 Delivery Year. Capacity Market Sellers shall use the one-year mothball Avoidable Cost Rate shown below, unless such Capacity Market Seller satisfies the criteria set forth in section 6.7(e) below, in which case the Capacity Market Seller may use the retirement Avoidable Cost Rate. PJM shall also publish on its Web site the number of Generation Capacity Resources and megawatts per LDA that use the retirement Avoidable Cost Rates. A Capacity Market Seller may not use the default Market Seller Offer Cap contained in the ACR tables in this subsection, and also seek to include any one or more categories of the Avoidable Cost Rate defined section 6.8 below.

Maximum Avoidable Cost Rates by Technology Class								
Technology	**2013/14 Mothball ACR ($/MW-Day)**	**2013/14 Retirement ACR ($/MW-Day)**	**2014/15 Mothball ACR ($/MW-Day)**	**2014/15 Retirement ACR ($/MW-Day)**	**2015/16 Mothball ACR ($/MW-Day)**	**2015/16 Retirement ACR ($/MW-Day)**	**2016/2017 Mothball ACR ($/MW-Day)**	**2016/2017 Retirement ACR ($/MW-Day)**
Nuclear	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pumped Storage	$23.64	$33.19	$24.56	$34.48	$25.56	$35.89	$24.05	$33.78
Hydro	$80.80	$105.67	$83.93	$109.76	$87.35	$114.24	$82.23	$107.55
Sub-Critical Coal	$193.98	$215.02	$201.49	$223.35	$209.71	$232.46	$197.43	$218.84
Super Critical Coal	$200.41	$219.21	$208.17	$227.70	$216.66	$236.99	$203.96	$223.10
Waste Coal - Small	$255.81	$309.83	$265.72	$321.83	$276.56	$334.96	$260.35	$315.34
Waste Coal – Large	$94.61	$114.29	$98.27	$118.72	$102.28	$123.56	$96.29	$116.32
Wind	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CC-2 on 1 Frame F	$35.18	$49.90	$36.54	$51.83	$38.03	$53.94	$35.81	$50.79
CC-3 on 1 Frame	$39.06	$52.89	$40.57	$54.94	$42.23	$57.18	$39.75	$53.83

E/Siemens								
CC–3 or More on 1 or More Frame F	$30.46	$42.28	$31.64	$43.92	$32.93	$45.71	$30.99	$43.03
CC-NUG Cogen. Frame B or E Technology	$130.76	$175.71	$135.82	$182.52	$141.36	$189.97	$133.09	$178.83
CT - 1st & 2nd Gen. Aero (P&W FT 4)	$27.96	$37.19	$29.04	$38.63	$30.22	$40.21	$28.45	$37.85
CT - 1st & Gen. Frame B	$27.63	$36.87	$28.70	$38.30	$29.87	$39.86	$28.11	$37.52
CT - 2nd Gen. Frame E	$26.26	$35.14	$27.28	$36.50	$28.39	$37.99	$26.73	$35.77
CT - 3rd Gen. Aero (GE LM 6000)	$63.57	$93.70	$66.03	$97.33	$68.72	$101.30	$64.70	$95.37
CT - 3rd Gen. Aero (P&W FT - 8 TwinPak)	$33.34	$49.16	$34.63	$51.06	$36.04	$53.14	$33.93	$50.03
CT - 3rd Gen. Frame F	$26.96	$38.83	$28.00	$40.33	$29.14	$41.98	$27.43	$39.52
Diesel	$29.92	$37.98	$31.08	$39.45	$32.35	$41.06	$30.44	$38.66
Oil and Gas Steam	$74.20	$90.33	$77.07	$93.83	$80.21	$97.66	$75.51	$91.94

Commencing with the Base Residual Auction for the 2017/2018 Delivery Year, the Office of the Interconnection shall determine the default retirement and mothball Avoidable Cost Rates referenced in section (c)(ii) above, and post them 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 applicable ACR rates, the Office of the Interconnection shall use the actual rate of change in the historical values from the Handy-Whitman Index of Public Utility Construction Costs or a comparable index approved by the Commission ("Handy-Whitman Index") to the extent they are available to update the base values for the Delivery Year, and for future Delivery Years for which the updated Handy-Whitman Index values are not yet available the Office of the Interconnection shall update the base values for the Delivery Year using the most recent ten-calendar-year annual average rate of change. The ACR rates shall be expressed in dollar values for the applicable Delivery Year.

Maximum Avoidable Cost Rates by Technology Class (Expressed in 2011 Dollars for the 2011/2012 Delivery Year)		
Technology	**Mothball ACR ($/MW-Day)**	**Retirement ACR ($/MW-Day)**
Combustion Turbine - Industrial Frame	$24.13	$33.04
Coal Fired	$136.91	$157.83
Combined Cycle	$29.58	$40.69
Combustion Turbine - Aero Derivative	$26.13	$37.18
Diesel	$25.46	$32.33
Hydro	$68.78	$89.96
Oil and Gas Steam	$63.16	$76.90
Pumped Storage	$20.12	$28.26

To determine the default retirement and mothball ACR values for the 2017/2018 Delivery Year, the Office of the Interconnection shall multiply the base default retirement and mothball ACR values in the table above by a factor equal to one plus the most recent annual average rate of change in the July Handy-Whitman Indices for the 2011 to 2013 calendar years to determine updated base default retirement and mothball ACR values. The updated base default retirement and mothball ACR values shall then be multiplied by a factor equal to one plus the most recent ten-calendar-year annual average rate of change in the applicable Handy-Whitman Index, taken to the fourth power, as calculated by the Office of the Interconnection and posted to its website.

To determine the default retirement and mothball ACR values for the 2018/2019 and 2019/2020 Delivery Years for Base Capacity Resources, the Office of the Interconnection shall multiply the updated base default retirement and mothball ACR values from the immediately preceding Delivery Year by a factor equal to one plus the most recent annual average rate of change in the July Handy-Whitman Index. These values become the new adjusted base default retirement and mothball ACR values, as calculated by the Office of the Interconnection and posted to its website. These resulting adjusted base values for the Delivery Year shall be multiplied by a factor equal to one plus the most recent ten-calendar-year annual average rate of change in the applicable Handy-Whitman Index, taken to the fourth power, as calculated by the Office of the Interconnection and posted to its website.

PJM shall also publish on its website the number of Generation Capacity Resources and megawatts per LDA that use the retirement Avoidable Cost Rates.

After the Market Monitoring Unit conducts its annual review of the table of default Avoidable Cost Rates included in section 6.7(c) above in accordance with the procedure specified in Tariff, Attachment M-Appendix, section II.H, it will provide updated values or notice of its determination that updated values are not needed to Office of the Interconnection. In the event that the Office of the Interconnection determines that the values should be updated, the Office of the Interconnection shall file its proposed values with the Commission by no later than October 30th prior to the commencement of the offer period for the first RPM Auction for which it proposes to apply the updated values.

(d) In order for costs to qualify for inclusion in the Market Seller Offer Cap, the Capacity Market Seller must provide to the Market Monitoring Unit and the Office of the Interconnection relevant unit-specific cost data concerning each data item specified as set forth in section 6 by no later than one hundred twenty (120) days prior to the commencement of the offer period for the applicable RPM Auction. If cost data is not available at the time of submission for the time periods specified in section 6.8 below, costs may be estimated for such period based on the most recent data available, with an explanation of and basis for the estimate used, as may be further specified in the PJM Manuals. Based on the data and calculations submitted by the Capacity Market Sellers for each existing generation resource and the formulas specified below, the Market Monitoring Unit shall calculate the Market Seller Offer Cap for each such resource, and notify the Capacity Market Seller and the Office of the Interconnection in writing of its determination pursuant to Tariff, Attachment M-Appendix, section II.E.

i. Avoidable Cost Rate: The Avoidable Cost Rate for an existing generation resource shall be determined using the formula below and applied to the unit's Base Offer Segment.

ii. Opportunity Cost: Opportunity Cost shall be the documented price available to an existing generation resource in a market external to PJM. In the event that the total MW of existing generation resources submitting opportunity cost offers in any auction for a Delivery Year exceeds the firm export capability of the PJM system for such Delivery Year, or the capability of external markets to import capacity in such year, the Office of the Interconnection will accept such offers on a competitive basis. PJM will construct a supply curve of opportunity cost offers, ordered by opportunity cost, and accept such offers to export starting with the highest opportunity cost, until the maximum level of such exports is reached. The maximum level of such exports is the lesser of the Office of the Interconnection's ability to permit firm exports or the ability of the importing area(s) to accept firm imports or imports of capacity, taking account of relevant export limitations by location. If, as a result, an opportunity cost offer is not accepted from an existing generation resource, the Market Seller Offer Cap applicable to Sell Offers relying on such generation resource shall be the Avoidable Cost Rate less the Projected Market Revenues for such resource (as defined in section 6.4 above). The default Avoidable Cost Rate shall be the one year mothball Avoidable Cost Rate set forth in the tables in section 6.7(c) above unless Capacity Market Seller satisfies the criteria delineated in section 6.7(e) below.

iii. Projected PJM Market Revenues: Projected PJM Market Revenues are defined by section 6.8(d) below, for any Generation Capacity Resource to which the Avoidable Cost Rate is applied.

(e) In order for the retirement Avoidable Cost Rate set forth in the table in section 6.7(c) to apply, by no later than one hundred twenty (120) days prior to the commencement of the offer period for the applicable RPM Auction, a Capacity Market Seller must submit to the Office of the Interconnection and the Market Monitoring Unit a written sworn, notarized statement of a corporate officer representing that the Capacity Market Seller will retire the Generation Capacity Resource if it does not receive during the relevant Delivery Year at least the applicable retirement Avoidable Cost Rate because it would be uneconomic to continue to operate the Generation Capacity Resource in the Delivery Year without the retirement Avoidable Cost Rate, and specifying the date the Generation Capacity Resource would otherwise be retired.

6.8 Avoidable Cost Definition

(a) **Avoidable Cost Rate**:

The Avoidable Cost Rate for a Generation Capacity Resource that is the subject of a Sell Offer shall be determined using the following formula, expressed in dollars per MW-year:

Avoidable Cost Rate = [Adjustment Factor * (AOML + AAE + AFAE + AME + AVE + ATFI + ACC + ACLE) + ARPIR + APIR + CPQR]

Where:

- **Adjustment Factor** equals 1.10 (to provide a margin of error for understatement of costs) plus an additional adjustment referencing the 10-year average Handy-Whitman Index in order to account for expected inflation from the time interval between the submission of the Sell Offer and the commencement of the Delivery Year.

- **AOML (Avoidable Operations and Maintenance Labor)** consists of the avoidable labor expenses related directly to operations and maintenance of the generating unit for the twelve months preceding the month in which the data must be provided. The categories of expenses included in AOML are those incurred for: (a) on-site based labor engaged in operations and maintenance activities; (b) off-site based labor engaged in on-site operations and maintenance activities directly related to the generating unit; and (c) off-site based labor engaged in off-site operations and maintenance activities directly related to generating unit equipment removed from the generating unit site.

    - **AAE (Avoidable Administrative Expenses)** consists of the avoidable administrative expenses related directly to employees at the generating unit for twelve months preceding the month in which the data must be provided. The categories of expenses included in AAE are those incurred for: (a) employee expenses (except employee expenses included in AOML); (b) environmental fees; (c) safety and operator training; (d) office supplies; (e) communications; and (f) annual plant test, inspection and analysis.

- **AFAE (Avoidable Fuel Availability Expenses) c**onsists of avoidable operating expenses related directly to fuel availability and delivery for the generating unit that can be demonstrated by the Capacity Market Seller based on data for the twelve months preceding the month in which the data must be provided , or on reasonable projections for the Delivery Year supported by executed contracts, published tariffs, or other data sufficient to demonstrate with reasonable certainty the level of costs that have been or shall be incurred for such purpose. The categories of expenses included in AFAE are those incurred for: (a) firm gas pipeline transportation; (b) natural gas storage costs; (c) costs of gas balancing agreements; and (d) costs of gas park and loan services. AFAE expenses are for firm fuel supply and apply solely for offers for a Capacity Performance Resource

- **AME (Avoidable Maintenance Expenses)** consists of avoidable maintenance expenses (other than expenses included in AOML) related directly to the generating unit for the twelve months preceding the month in which the data must be provided. The categories of expenses included in AME are those incurred for: (a) chemical and materials consumed during maintenance of the generating unit; and (b) rented maintenance equipment used to maintain the generating unit.

- **AVE (Avoidable Variable Expenses)** consists of avoidable variable expenses related directly to the generating unit incurred in the twelve months preceding the month in which the data must be provided. The categories of expenses included in AVE are those incurred for: (a) water treatment chemicals and lubricants; (b) water, gas, and electric service (not for power generation); and (c) waste water treatment.

- **ATFI (Avoidable Taxes, Fees and Insurance)** consists of avoidable expenses related directly to the generating unit incurred in the twelve months preceding the month in which the data must be provided. The categories of expenses included in AFTI are those incurred for: (a) insurance, (b) permits and licensing fees, (c) site security and utilities for maintaining security at the site; and (d) property taxes.

- **ACC (Avoidable Carrying Charges)** consists of avoidable short-term carrying charges related directly to the generating unit in the twelve months preceding the month in which the data must be provided. Avoidable short-term carrying charges shall include short term carrying charges for maintaining reasonable levels of inventories of fuel and spare parts that result from short-term operational unit decisions as measured by industry best practice standards. For the purpose of determining ACC, short term is the time period in which a reasonable replacement of inventory for normal, expected operations can occur.

- **ACLE (Avoidable Corporate Level Expenses)** consists of avoidable corporate level expenses directly related to the generating unit incurred in the twelve months preceding the month in which the data must be provided. Avoidable corporate level expenses shall include only such expenses that are directly linked to providing tangible services required for the operation of the generating unit proposed for Deactivation. The categories of avoidable expenses included in ACLE are those incurred for: (a) legal services, (b) environmental reporting; and (c) procurement expenses.

- **CPQR (Capacity Performance Quantifiable Risk)** consists of the quantifiable and reasonably-supported costs of mitigating the risks of non-performance associated with submission of a Capacity Performance Resource offer (or of a Base Capacity Resource offer for the 2018/19 or 2019/20 Delivery Years), such as insurance expenses associated with resource non-performance risks. CPQR shall be considered reasonably supported if it is based on actuarial practices generally used by the industry to model or value risk and if it is based on actuarial practices used by the Capacity Market Seller to model or value risk in other aspects of the Capacity Market Seller's business. Such reasonable support shall also include an officer certification that the modeling and valuation of the CPQR was developed in accord with such practices. Provision of such reasonable support shall be sufficient to establish the CPQR. A Capacity Market Seller may use other methods or forms of support for its proposed CPQR that shows the CPQR is limited to risks the seller faces from committing a Capacity Resource hereunder, that quantifies the costs of mitigating such risks, and that includes supporting documentation (which may include an officer certification) for the identification of such risks and quantification of such costs. Such showing shall establish the proposed CPQR upon acceptance by the Office of the Interconnection.

- **APIR (Avoidable Project Investment Recovery Rate) = PI * CRF**

Where:

  - **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.

- **CRF** is the annual capital recovery factor from the following table, applied in accordance with the terms specified below.

Age of Existing Units (Years)	Remaining Life of Plant (Years)	Levelized CRF
1 to 5	30	0.107
6 to 10	25	0.114
11 to 15	20	0.125
16 to 20	15	0.146
21 to 25	10	0.198
25 Plus	5	0.363
Mandatory CapEx	4	0.450
40 Plus Alternative	1	1.100

Unless otherwise stated, Age of Existing Unit shall be equal to the number of years since the Unit commenced commercial operation, up to and through the relevant Delivery Year.

Remaining Life of Plant defines the amortization schedule (i.e., the maximum number of years over which the Project Investment may be included in the Avoidable Cost Rate.)

Capital Expenditures and Project Investment

For any given Project Investment, a Capacity Market Seller may make a one-time election to recover such investment using: (i) the highest CRF and associated recovery schedule to which it is entitled; or (ii) the next highest CRF and associated recovery schedule. For these purposes, the CRF and recovery schedule for the 25 Plus category is the next highest CRF and recovery schedule for both the Mandatory CapEx and the 40 Plus Alternative categories. The Capacity Market Seller using the above table must provide the Market Monitoring Unit with information, identifying and supporting such election, including but not limited to the age of the unit, the amount of the Project Investment, the purpose of the investment, evidence of corporate commitment (e.g., an SEC filing, a press release, or a letter from a duly authorized corporate officer indicating intent to make such investment), and detailed information concerning the governmental requirement (if applicable). Absent other written notification, such election shall be deemed based on the CRF such Seller employs for the first Sell Offer reflecting recovery of any portion of such Project Investment.

For any resource using the CRF and associated recovery schedule from the CRF table that set the Capacity Resource Clearing Price in any Delivery Year, such Capacity Market Seller must also provide to the Market Monitoring Unit, for informational purposes only, evidence of the actual expenditure of the Project Investment, when such information becomes available.

If the project associated with a Project Investment that was included in a Sell Offer using a CRF and associated recovery schedule from the above table has not entered into commercial operation prior to the end of the relevant Delivery Year, and the resource's Sell Offer sets the clearing price for the relevant LDA, the Capacity Market Seller shall be required to elect to either (i) pay a charge that is equal to the difference between the Capacity Resource Clearing Price for such LDA for the relevant Delivery Year and what the clearing price would have been absent the

APIR component of the Avoidable Cost Rate, this difference to be multiplied by the cleared MW volume from such Resource ("rebate payment"); (ii) hold such rebate payment in escrow, to be released to the Capacity Market Seller in the event that the project enters into commercial operation during the subsequent Delivery Year or rebated to LSEs in the relevant LDA if the project has not entered into commercial operation during the subsequent Delivery Year; or (iii) make a reasonable investment in the amount of the PI in other Existing Generation Capacity Resources owned or controlled by the Capacity Market Seller or its Affiliates in the relevant LDA. The revenue from such rebate payments shall be allocated pro rata to LSEs in the relevant LDA(s) that were charged a Locational Reliability Charge for such Delivery Year, based on their Daily Unforced Capacity Obligation in the relevant LDA(s). If the Sell Offer from the Generation Capacity Resource did not set the Capacity Resource Clearing Price in the relevant LDA, no alternative investment or rebate payment is required. If the difference between the Capacity Resource Clearing Price for such LDA for the relevant Delivery Year and what the clearing price would have been absent the APIR amount does not exceed the greater of $10 per MW-day or a 10% increase in the clearing price, no alternative investment or rebate payment is required.

Mandatory CapEx Option

The Mandatory CapEx CRF and recovery schedule is an option available, beginning in the third BRA (Delivery Year 2009-10), to a resource that must make a Project Investment to comply with a governmental requirement that would otherwise materially impact operating levels during the Delivery Year, where: (i) such resource is a coal, oil or gas-fired resource that began commercial operation no fewer than fifteen years prior to the start of the first Delivery Year for which such recovery is sought, and such Project Investment is equal to or exceeds $200/kW of capitalized project cost; or (ii) such resource is a coal-fired resource located in an LDA for which a separate VRR Curve has been established for the relevant Delivery Years, and began commercial operation at least 50 years prior to the conduct of the relevant BRA.

A Capacity Market Seller that wishes to elect the Mandatory CapEx option for a Project Investment must do so beginning with the Base Residual Auction for the Delivery Year in which such project is expected to enter commercial operation. A Sell Offer submitted in any Base Residual Auction for which the Mandatory CapEx option is selected may not exceed an offer price equivalent to 0.90 times the then-current Net CONE (on an unforced-equivalent basis).

40 Plus Alternative Option

The 40 Plus Alternative CRF and recovery schedule is an option available, beginning in the third BRA (Delivery Year 2009-10), for a resource that is a gas- or oil-fired resource that began commercial operation no less than 40 years prior to the conduct of the relevant BRA (excluding, however, any resource in any Delivery Year for which the resource is receiving a payment under Tariff, Part V. Generation Capacity Resources electing this 40 Plus Alternative CRF shall be treated as At Risk Generation for purposes of the sensitivity runs in the RTEP process). Resources electing the 40 Plus Alternative option will be modeled in the RTEP process as "at-risk" at the end of the one-year amortization period.

A Capacity Market Seller that wishes to elect the 40 Plus Alternative option for a Project Investment must provide written notice of such election to the Office of the Interconnection no later than six months prior to the Base Residual Auction for which such election is sought; provided however that shorter notice may be provided if unforeseen circumstances give rise to the need to make such election and such seller gives notice as soon as practicable.

The Office of the Interconnection shall give market participants reasonable notice of such election, subject to satisfaction of requirements under the PJM Operating Agreement for protection of confidential and commercially sensitive information. A Sell Offer submitted in any Base Residual Auction for which the 40 Plus Alternative option is selected may not exceed an offer price equivalent to the then-current Net CONE (on an unforced-equivalent basis).

Multi-Year Pricing Option

A Seller submitting a Sell Offer with an APIR component that is based on a Project Investment of at least $450/kW may elect this Multi-Year Pricing Option by providing written notice to such effect the first time it submits a Sell Offer that includes an APIR component for such Project Investment. Such option shall be available on the same terms, and under the same conditions, as are available to Planned Generation Capacity Resources under Tariff, Attachment DD, section 5.14(c).

- **ARPIR (Avoidable Refunds of Project Investment Reimbursements)** consists of avoidable refund amounts of Project Investment Reimbursements payable by a Generation Owner to PJM under Tariff, Part V, section 118 or avoidable refund amounts of project investment reimbursements payable by a Generation Owner to PJM under a Cost of Service Recovery Rate filed under Tariff, Part V, section 119 and approved by the Commission.

(b) For the purpose of determining an Avoidable Cost Rate, avoidable expenses are incremental expenses directly required to operate a Generation Capacity Resource that a Generation Owner would not incur if such generating unit did not operate in the Delivery Year or meet Availability criteria during Peak-Hour Periods during the Delivery Year.

(c) Variable costs that are directly attributable to the production of energy shall be excluded from a Market Seller's generation resource Avoidable Cost Rate. Notwithstanding the foregoing, a Market Seller that included variable costs attributable to the production of energy in a generation resource's Avoidable Cost Rate prior to April 15, 2019 shall not include such costs in such generation resource's Maintenance Adders or Operating Costs for any Delivery Year for which it has already included such costs in the generation resource's Avoidable Cost Rate. A Market Seller implicated by this paragraph may continue including such variable costs attributable to the production of energy in its Avoidable Cost Rate for each generation resource for any Delivery Year for which it already did so prior to April 15, 2019.

(d) Projected PJM Market Revenues for any Generation Capacity Resource to which the Avoidable Cost Rate is applied shall include all actual unit-specific revenues from PJM energy markets, ancillary services, and unit-specific bilateral contracts from such Generation Capacity Resource, net of energy and ancillary services market offers for such resource. Net energy market revenues shall be based on the non-zero market-based offers of the Capacity

Market Seller of such Generation Capacity Resource unless one of the following conditions is met, in which case the cost-based offer shall be used: (x) the market-based offer for the resource is zero, (y) the market-based offer for the resource is higher than its cost-based offer and such offer has been mitigated, or (z) the market-based offer for the resource is less than such Capacity Market Seller's fuel and environmental costs for the resource which shall be determined either by directly summing the fuel and environmental costs if they are available, or by subtracting from the cost-based offer for the resource all costs developed pursuant to the Operating Agrement and PJM Manuals that are not fuel or environmental costs.

The calculation of Projected PJM Market Revenues shall be equal to the rolling simple average of such net revenues as described above from the three most recent whole calendar years prior to the year in which the BRA is conducted.

If a Generation Capacity Resource did not receive PJM market revenues during the entire relevant time period because the Generation Capacity Resource was not integrated into PJM during the full period, then the Projected PJM Market Revenues shall be calculated using only those whole calendar years within the full period in which such Resource received PJM market revenues.

If a Generation Capacity Resource did not receive PJM market revenues during the entire relevant time period because it was not in commercial operation during the entire period, or if data is not available to the Capacity Market Seller for the entire period, despite the good faith efforts of such seller to obtain such data, then the Projected PJM Market Revenues shall be calculated based upon net revenues received over the entire period by comparable units, to be developed by the MMU and the Capacity Market Seller.

ATTACHMENT DD-1

Preface: The provisions of this Attachment incorporate into the Tariff for ease of reference the provisions of Schedule 6 of the Reliability Assurance Agreement among Load Serving Entities in the PJM Region. As a result, this Attachment will be modified, subject to FERC approval, so that the terms and conditions set forth herein remain consistent with the corresponding terms and conditions of RAA, Schedule 6. Capitalized terms used herein that are not otherwise defined in Tariff, Attachment DD or elsewhere in this Tariff have the meaning set forth in the RAA.

PROCEDURES FOR DEMAND RESOURCES AND ENERGY EFFICIENCY

A. Parties can partially or wholly offset the amounts payable for the Locational Reliability Charge with Demand Resources that are operated under the direction of the Office of the Interconnection. FRR Entities may reduce their capacity obligations with Demand Resources that are operated under the direction of the Office of the Interconnection and detailed in such entity's FRR Capacity Plan. Demand Resources qualifying under the criteria set forth below may be offered for sale or designated as Self-Supply in the Base Residual Auction, included in an FRR Capacity Plan, or offered for sale in any Incremental Auction, for any Delivery Year for which such resource qualifies. Qualified Demand Resources generally fall in one of two categories, i.e., Guaranteed Load Drop or Firm Service Level, as further specified in section G below and the PJM Manuals. Qualified Demand Resources may be provided by a Curtailment Service Provider, notwithstanding that such Curtailment Service Provider is not a Party to this Agreement. Such Curtailment Service Providers must satisfy the requirements hereof and the PJM Manuals.

1. A Party must formally notify, in accordance with the requirements of the PJM Manuals and section F hereof, as applicable, the Office of the Interconnection of the Demand Resource Registration that it is placing under the direction of the Office of the Interconnection. A Party must further notify the Office of the Interconnection whether the Demand Resource Registration is linked to a Limited Demand Resource, an Extended Summer Demand Resource, a Base Capacity Demand Resource, a Summer-Period Demand Resource or an Annual Demand Resource.

2. A Demand Resource Registration must achieve its full load reduction within the following time period:

(a) For the 2015/2016 Delivery Year and subsequent Delivery Years, a Demand Resource Registration must be able to fully respond to a Load Management Event within 30 minutes of notification from the Office of the Interconnection. This default 30 minute prior notification shall apply unless a Curtailment Service Provider obtains an exception from the Office of the Interconnection due to physical operational limitations that prevent the Demand Resource Registration from reducing load within that timeframe. In such case, the Curtailment Service Provider shall submit a request for an exception to the 30 minute prior notification requirement to the Office of the Interconnection, at the time the Registration Form for that Demand Resource Registration is submitted in accordance with Tariff, Attachment K-Appendix. The only alternative notification times that the Office of Interconnection will permit, upon approval of an exception request, are 60 minutes and 120 minutes prior to a Load Management Event. The Curtailment Service Provider shall indicate in writing, in the appropriate application, that it seeks an exception to permit a prior notification time of 60 minutes or 120 minutes, and the reason(s) for the requested exception. A Curtailment Service Provider shall not submit a request for an exception to the default 30 minute notification period unless it has done its due diligence to confirm that the Demand Resource Registration is physically incapable of responding within that timeframe based on one or more of the reasons set forth below and as may be further defined in the PJM Manuals and has obtained detailed data and documentation to support this determination.

In order to establish that a Demand Resource Registration is reasonably expected to be physically unable to reduce load in that timeframe, the Curtailment Service Provider that submitted the Demand Resource Registration must demonstrate that:

(i) The manufacturing processes for the Demand Resource Registration require gradual reduction to avoid damaging major industrial equipment used in the manufacturing process, or damage to the product generated or feedstock used in the manufacturing process;

(ii) Transfer of load to back-up generation requires time-intensive manual process taking more than 30 minutes;

(iii) On-site safety concerns prevent location from implementing reduction plan in less than 30 minutes; or,

(iv) The Demand Resource Registration is comprised of mass market residential customers or Small Commercial Customers which collectively cannot be notified of a Load Management Event within a 30-minute timeframe due to unavoidable communications latency, in which case the requested notification time shall be no longer than 120 minutes.

The Office of the Interconnection may request data and documentation from the Curtailment Service Provider and such Curtailment Service Provider shall provide to the Office of the Interconnection within three (3) Business Days of a request therefor, a copy of all of the data and documentation supporting the exception request. Failure to provide a timely response to such request shall cause the exception to terminate the following Operating Day.

At its sole option and discretion, the Office of the Interconnection may review the data and documentation provided by the Curtailment Service Provider to determine if the Demand Resource Registration has met one or more of the criteria above. The Office of the

Interconnection will notify the Curtailment Service Provider in writing of its determination by no later than ten (10) Business Days after receipt of the data and documentation.

The Curtailment Service Provider shall provide written notification to the Office of the Interconnection of a material change to the facts that supported its exception request within three (3) Business Days of becoming aware of such material change in facts, and, if the Office of Interconnection determines that the physical limitation criteria above are no longer being met, the Demand Resource Registration shall be subject to the default notification period of 30 minutes immediately upon such determination.

3. The initiation of load reduction, upon the request of the Office of the Interconnection, must be within the authority of the dispatchers of the Party. No additional approvals should be required.

4. The initiation of load reduction upon the request of the Office of the Interconnection is considered a pre-emergency or emergency action and must be implementable prior to a voltage reduction.

5. A Curtailment Service Provider intending to offer for sale or designate for self-supply, a Demand Resource in any RPM Auction, or intending to include a Demand Resource in any FRR Capacity Plan must demonstrate, to PJM's satisfaction, that such resource shall have the capability to provide a reduction in demand, or otherwise control load, on or before the start of the Delivery Year for which such resource is committed. As part of such demonstration, each such Curtailment Service Provider shall submit a Demand Resource Sell Offer Plan in accordance with the standards and procedures set forth in RAA, Schedule 6, section A-1; RAA, Schedule 8.1 (as to FRR Capacity Plans) and the PJM Manuals, no later than 30~~15 Business~~ d~~D~~ays prior to, as applicable, the RPM Auction in which such resource is to be offered, or the deadline for submission of the FRR Capacity Plan in which such resource is to be included. PJM may verify the Curtailment Service Provider's adherence to the Demand Resource Sell Offer Plan at any time. A Curtailment Service Provider with a PJM-approved Demand Resource Sell Offer Plan will be permitted to offer up to the approved Demand Resource quantity into the subject RPM Auction or include such resource in its FRR Capacity Plan.

6. Selection of a Demand Resource in an RPM Auction results in commitment of capacity to the PJM Region. Demand Resources that are so committed must be linked to registrations participating in the Full Program Option or Capacity Only Option of the Emergency Load Response and Pre-Emergency Load Response Program and thus available for dispatch during PJM-declared pre-emergency events and emergency events.

A-1. A Demand Resource Sell Offer Plan shall consist of a completed template document in the form posted on the PJM website, requiring the information set forth below and in the PJM Manuals, and a Demand Resource Officer Certification Form signed by an officer of the Demand Resource Provider that is duly authorized to provide such a certification. The Demand Resource Sell Offer Plan must provide information that supports the Demand Resource Provider's intended Demand Resource Sell Offers and demonstrates that the Demand Resources are being offered with the intention that the MW quantity that clears the auction is reasonably expected to be physically delivered through Demand Resource registrations for the relevant Delivery Year. The Demand Resource Sell Offer Plan shall include all Existing Demand Resources and all Planned Demand Resources that the Demand Resource Provider intends to offer into an RPM Auction or include in an FRR Capacity Plan.

1. Demand Resource Sell Offer Plan Template. The Demand Resource Sell Offer Plan template, in the form provided on the PJM website, shall require the Demand Resource Provider to provide the following information and such other information as specified in the PJM Manuals:

(a) Summary Information. The completed template shall include the Demand Resource Provider's company name, contact information, and the Nominated DR Value in ICAP MWs by Zone/sub-Zone that the Demand Resource Provider intends to offer, stated separately for Existing Demand Resources and Planned Demand Resources. The total Nominated DR Value in MWs for each Zone/sub-Zone shall be the sum of the Nominated DR Value of Existing Demand Resources and the Nominated DR Value of Planned Demand Resources, and shall be the maximum MW amount the Provider intends to offer in the RPM Auction for the indicated Zone/sub-Zone, provided that nothing herein shall preclude the Demand Resource Provider from offering in the auction a lesser amount than the total Nominated DR Value shown in its Demand Resource Sell Offer Plan.

(b) Existing Demand Resources. The Demand Resource Provider shall identify all Existing Demand Resources by identifying end-use customer sites that are currently registered with PJM (even if not registered by such Demand Resource Provider) and that the Demand Resource Provider reasonably expects to have under a contract to reduce load based on PJM dispatch instructions by the start of the auction Delivery Year.

(c) Planned Demand Resources. The Demand Resource Provider shall provide the details of, and key assumptions underlying, the Planned Demand Resource quantities (i.e., all Demand Resource quantities in excess of Existing Demand Resource quantities) contained in the Demand Resource Sell Offer Plan, including:

(i) key program attributes and assumptions used to develop the Planned Demand Resource quantities, including, but not limited to, discussion of:

- method(s) of achieving load reduction at customer site(s);
- equipment to be controlled or installed at customer site(s), if any;
- plan and ability to acquire customers;

- types of customer targeted;
- support of market potential and market share for the target customer base, with adjustments for Existing Demand Resource customers within this market and the potential for other Demand Resource Providers targeting the same customers; and
- assumptions regarding regulatory approval of program(s), if applicable.

(ii) Zone/sub-Zone information by end-use customer segment for all Nominated DR Values for which an end-use customer site is not identified, to include the number in each segment of end-use customers expected to be registered for the subject Delivery Year, the average Peak Load Contribution per end-use customer for such segment, and the average Nominated DR Value per customer for such segment. End-use customer segments may include residential, commercial, small industrial, medium industrial, and large industrial, as identified and defined in the PJM Manuals, provided that nothing herein or in the Manuals shall preclude the Provider from identifying more specific customer segments within the commercial and industrial categories, if known.

(iii) Information by end-use customer site to the extent required by subsection A-1(1)(c)(iv) or, if not required by such subsection, to the extent known at the time of the submittal of the Demand Resource Sell Offer Plan, to include: customer EDC account number (if known), customer name, customer premise address, Zone/sub-Zone in which the customer is located, end-use customer segment, current Peak Load Contribution value (or an estimate if actual value not known) and an estimate of expected Peak Load Contribution for the subject Delivery Year, and an estimated Nominated DR Value.

(iv) End-use customer site-specific information shall be required for any Zones or sub-Zones identified by PJM pursuant to this subsection for the portion, if any, of a Demand Resource Provider's intended offer in such Zones or sub-Zones that exceeds a Sell Offer threshold determined pursuant to this subsection, as any such excess quantity under such conditions should reflect Planned Demand Resources from end-use customer sites that the Provider has a high degree of certainty it will physically deliver for the subject Delivery Year. In accordance with the procedures in subsection A-1(3) below, PJM shall identify, as requiring site-specific information, all Zones and sub-Zones that comprise any LDA group (from a list of LDA groups stated in the PJM Manuals) in which [the quantity of cleared Demand Resources from the most recent Base Residual Auction] plus [the quantity of Demand Resources included in FRR Capacity Plans for the Delivery Year addressed by the most recent Base Residual Auction] in any Zone or sub-Zone of such LDA group exceeds the greater of:

- the maximum Demand Resources quantity registered with PJM for such Zone for any Delivery Year from the current (at time of plan submission) Delivery Year and the two preceding Delivery Years; and

- the potential Demand Resource quantity for such Zone estimated by PJM based on an independent published assessment of demand response potential that is reasonably applicable to such Zone, as identified in the PJM Manuals.

For each such Zone and sub-Zone, the Sell Offer threshold for each Demand Resource Provider shall be the higher of:

- the Demand Resource Provider's maximum Demand Resource quantity registered with PJM for such Zone/sub-Zone over the current Delivery Year (at the time of plan submission) and two preceding Delivery Years;

- the Demand Resource Provider's maximum for any single Delivery Year of [such provider's cleared Demand Resource quantity] plus [such provider's quantity of Demand Resources included in FRR Capacity Plans] from the three forward Delivery Years addressed by the three most recent Base Residual Auctions for such Zone/sub-Zone; and

- 10 MW.

(d) Schedule. The Demand Resource Provider shall provide an approximate timeline for procuring end-use customer sites as needed to physically deliver the total Nominated DR Value (for both Existing Demand Resources and Planned Demand Resources) by Zone/sub-Zone in the Demand Resource Sell Offer Plan. The Demand Resource Provider must specify the cumulative number of customers and the cumulative Nominated DR Value associated with each end-use customer segment within each Zone/sub-Zone that the Demand Resource Provider expects (at the time of plan submission) to have under contract as of June 1 each year between the time of the auction and the subject Delivery Year.

(e) Minimum Offer Price Rule for Demand Resources. The Demand Resource Provider shall certify whether or not the Existing Demand Resource end use customer site(s) and Planned Demand Resource is entitled to a State Subsidy. Such certifications shall be made separately for end-use customer locations that are entitled to receive State Subsidy and those that are not, in accordance with the procedures provided in the

PJM Manuals, to ensure the accurate application of the Minimum Offer Price Rules. Sell Offers for Demand Resources that are Capacity Resources with State Subsidy shall be offered separately for load-backed Demand Resources and generation-backed Demand Resources, unless the Capacity Market Seller for such Capacity Resource with State Subsidy elects the competitive exemption pursuant to Tariff, Attachment DD, section 5.14(h).

2. Demand Resource Officer Certification Form. Each Demand Resource Sell Offer Plan must include a Demand Resource Officer Certification, signed by an officer of the Demand Resource Provider that is duly authorized to provide such a certification, in the form shown in the PJM Manuals, which form shall include the following certifications:

(a) that the signing officer has reviewed the Demand Resource Sell Offer Plan and the information supplied to PJM in support of the Plan is true and correct as of the date of the certification; and

(b) that the Demand Resource Provider is submitting the Plan with the reasonable expectation, based upon its analyses as of the date of the certification, to physically deliver all megawatts that clear the RPM Auction through Demand Resource registrations by the specified Delivery Year.

As set forth in the form provided in the PJM Manuals, the certification shall specify that it does not in any way abridge, expand, or otherwise modify the current provisions of the PJM Tariff, Operating Agreement and/or RAA, or the Demand Resource Provider's rights and obligations thereunder, including the Demand Resource Provider's ability to adjust capacity obligations through participation in PJM incremental auctions and bilateral transactions.

3. Procedures. No later than December 1 prior to the Base Residual Auction for a Delivery Year, PJM shall post to the PJM website a list of Zones and sub-Zones, if any, for which end-use customer site-specific information shall be required under the conditions specified in subsection A-1(1)(c)(iv) above for all RPM Auctions conducted for such Delivery Year. Once so identified, a Zone or sub-Zone shall remain on the list for future Delivery Years until the threshold determined under subsection A-1(1)(c)(iv) above is not exceeded for three consecutive Delivery Years. No later than 30~~15 Business D~~days prior to the RPM Auction in which a Demand Resource Provider intends to offer a Demand Resource, the Demand Resource Provider shall submit to PJM a completed Demand Resource Sell Offer Plan template and a Demand Resource Officer Certification Form signed by a duly authorized officer of the Provider. PJM will review all submitted DR Sell Offer Plans. No later than 10 Business Days prior to the subject RPM Auction, PJM shall notify any Demand Resource Providers that have identified the same end-use customer site(s) in their respective DR Sell Offer Plans for the same Delivery Year. In such event, the MWs associated with such site(s) will not be approved for inclusion in a Sell Offer in an RPM Auction by

any of the Demand Resource Providers, unless a Demand Resource Provider provides a letter of support from the end-use customer indicating that it is likely to execute a contract with that Demand Resource Provider for the relevant Delivery Year, or provides other comparable evidence of likely commitment. Such letter of support or other supporting evidence must be provided to PJM no later than 7 Business Days prior to the subject RPM Auction. If an end-use customer provides letters of support for the same site for the same Delivery Year to multiple Demand Resource Providers, the MWs associated with such end-use customer site shall not be approved as a Demand Resource for any of the Demand Resource Providers. No later than 5 Business Days prior to the subject RPM Auction, PJM will notify each Demand Resource Provider of the approved Demand Resource quantity, by Zone/sub-Zone, that such Demand Resource Provider is permitted to offer into such RPM Auction.

B. The Unforced Capacity value of a Demand Resource will be determined as:

for the Delivery Years through May 31, 2018, or for FRR Capacity Plans for Delivery Years through May 31, 2019, the product of the Nominated Value of the Demand Resource, times the DR Factor, times the Forecast Pool Requirement, and for the 2018/2019 Delivery Year and subsequent Delivery Years, or for FRR Capacity Plans for the 2019/2020 Delivery Year and subsequent Delivery Years, the product of the Nominated Value of the Demand Resource times the Forecast Pool Requirement. Nominated Values shall be determined and reviewed in accordance with sections I and J, respectively, and the PJM Manuals. The DR Factor is a factor established by the PJM Board with the advice of the Members Committee to reflect the increase in the peak load carrying capability in the PJM Region due to Demand Resources. Peak load carrying capability is defined to be the peak load that the PJM Region is able to serve at the loss of load expectation defined in the Reliability Principles and Standards. The DR Factor is the increase in the peak load carrying capability in the PJM Region due to Demand Resources, divided by the total Nominated Value of Demand Resources in the PJM Region. The DR Factor will be determined using an analytical program that uses a probabilistic approach to determine reliability. The determination of the DR Factor will consider the reliability of Demand Resources, the number of interruptions, and the total amount of load reduction.

C. Demand Resources offered and cleared in a Base Residual or Incremental Auction shall receive the corresponding Capacity Resource Clearing Price as determined in such auction, in accordance with Tariff, Attachment DD. For Delivery Years beginning with the Delivery Year that commences on June 1, 2013, any Demand Resources located in a Zone with multiple LDAs shall receive the Capacity Resource Clearing Price applicable to the location of such resource within such Zone, as identified in such resource's offer. Further, the Curtailment Service Provider shall register its resource in the same location within the Zone as specified in its cleared sell offer, and shall be subject to deficiency charges under Tariff, Attachment DD to the extent it fails to provide the resource in such location consistent with its cleared offer.

D. The Party, Electric Distributor, or Curtailment Service Provider that establishes a contractual relationship (by contract or tariff rate) with a customer for load reductions is entitled to receive the compensation specified in section C for a committed Demand Resource, notwithstanding that such provider is not the customer's energy supplier.

E. Any Party hereto shall demonstrate that its Demand Resources performed during periods when load management procedures were invoked by the Office of the Interconnection. The Office of the Interconnection shall adopt and maintain rules and procedures for verifying the performance of such resources, as set forth in section K hereof and the PJM Manuals. In addition, committed Demand Resources that do not comply with the directions of the Office of the Interconnection to reduce load during an emergency shall be subject to the penalty charge set forth in Tariff, Attachment DD.

F. Parties may elect to place Demand Resources associated with Behind The Meter Generation under the direction of the Office of the Interconnection for a Delivery Year by submitting a Sell Offer for such resource (as Self Supply, or with an offer price) in the Base Residual Auction for such Delivery Year. This election shall remain in effect for the entirety of such Delivery Year. In the event such an election is made, such Behind The Meter Generation will not be netted from load for the purposes of calculating the Daily Unforced Capacity Obligations under this Agreement.

G. PJM measures Demand Resource Registrations in the following ways:

Firm Service Level (FSL) – Load management achieved by an end-use customer reducing its load to a pre-determined level (the Firm Service Level), upon notification from the Curtailment Service Provider's market operations center or its agent.

Guaranteed Load Drop (GLD) – Load management achieved by an end-use customer reducing its load by a pre-determined amount (the Guaranteed Load Drop), upon notification from the Curtailment Service Provider's market operations center or its agent. Typically, the load reduction is achieved through running customer-owned backup generators, or by shutting down process equipment.

H. Each Curtailment Service Provider must satisfy (or contract with another LSE, Curtailment Service Provider, or electric distribution company to provide) the following requirements:

- A point of contact with appropriate backup to ensure single call notification from PJM and timely execution of the notification process;

- Supplemental status reports, detailing Demand Resources available, as requested by PJM;

- Entry of customer-specific Demand Resource Registration information, for planning and verification purposes, into the designated PJM electronic system.

● Customer-specific compliance and verification information for each PJM-initiated Demand Resource event or Provider initiated test event, as well as aggregated Provider load drop data for Provider-initiated events, in accordance with established reporting guidelines.

● Load drop estimates for all Load Management events and test events, prepared in accordance with the PJM Manuals.

I. The Nominated Values (summer, winter or annual) for each Demand Resource Registration shall be determined consistent with the process described below.

The summer Nominated Value for Firm Service Level customer(s) on a registration will be based on the peak load contribution for the customer(s), as typically determined by the 5CP methodology utilized by the electric distribution company to determine ICAP obligation values. The summer Nominated Value for a registration shall equal the total peak load contribution for the customers on the registration minus the summer Firm Service Level multiplied by the loss factor. The winter Nominated Value for Firm Service Level customer(s) on a registration shall equal the total Winter Peak Load for customers on the registration multiplied by Zonal Winter Weather Adjustment Factor minus winter Firm Service level and then the result is multiplied by the loss factor. The annual Nominated Value for or Firm Service Level customer(s) on a registration shall equal the lesser of i) summer Nominated Value or ii) winter Nominated Value. Effective with the 2019/2020 Delivery Year, an annual Nominated Value for a registration is no longer calculated.

The summer Nominated Value for a Guaranteed Load Drop customer on a registrationshall equal the summer guaranteed load drop amount, adjusted for system losses and shall not exceed the customer’s Peak Load Contribution, as established by the customer’s contract with the Curtailment Service Provider. The winter Nominated Value for a Guaranteed Load Drop customer on a registration shall be the winter guaranteed load drop amount, adjusted for system losses, and shall not exceed the customer’s Winter Peak Load multiplied by Zonal Winter Weather Adjustment Factor multiplied by the loss factor, as established by the customer’s contract with the Curtailment Service Provider. The annual Nominated Value for a Guaranteed Load Drop customer on a registration shall be the lesser of the i) summer Nominated Value or ii) winter Nominated Value. Effective with the 2019/2020 Delivery Year, an annual Nominated Value for a registration is no longer calculated.

Customer-specific Demand Resource Registration information (EDC account number, peak load contribution, Winter Peak Load, notification period, etc.) will be entered into the designated PJM electronic system to establish nominated values. Each Demand Resource Registration should be linked to a Demand Resource. Additional data may be required, as defined in sections J and K and the PJM Manuals.

J. Nominated Values shall be reviewed based on documentation of customer-specific data and Demand Resource Registration information, to verify the amount of load management available and to set a summer, winter, or annual Nominated Value. Data is provided by both the zone EDC and the Curtailment Service Provider in the designated PJM electronic system, and must include the EDC meter number or other unique customer identifier, Peak Load Contribution (5CP), Winter Peak Load, contract firm service level or guaranteed load drop values, applicable loss factor, zone/area location of the load drop, number of active participants, etc. Such data must be uploaded and approved prior to the first day of the Delivery Year for which such Demand Resource Registration is effective. Curtailment Service Providers must provide this information concurrently to host EDCs.

For Firm Service Level and Guaranteed Load Drop customers, the 5CP values, for the zone and affected customers, will be adjusted to reflect an "unrestricted" peak for a zone, based on information provided by the Curtailment Service Provider. Load drop levels shall be estimated in accordance with guidelines in the PJM Manuals.

The daily Nominated Value for the Delivery Year for a Limited Demand Resource, Extended Summer Demand Resource, Base Capacity Demand Resource, and Annual Demand Resource without a Capacity Performance commitment shall equal the sum of the summer Nominated Values of the registrations linked to such Demand Resource. For the 2017/2018 and 2018/2019 Delivery Years, the daily Nominated Value for the Delivery Year for an Annual Demand Resource with a Capacity Performance commitment shall equal the sum of the annual Nominated Values of the registrations linked to such Demand Resource. For the 2019/2020 Delivery Year, the daily Nominated Value for the Delivery Year for an Annual Demand Resource with a Capacity Performance commitment shall equal the lesser of (i) the sum of the summer Nominated Values of the registrations linked to such Demand Resource or (ii) the sum of the winter Nominated Values of the registrations linked to such Demand Resource. Effective with the 2020/2021 Delivery Year, the daily Nominated Value of a Demand Resource with a Capacity Performance commitment (which may consist of an Annual Demand Resource with a Capacity Performance commitment and/or Summer Period Demand Resource with a Capacity Performance commitment) shall equal the sum of the summer Nominated Values of the registrations linked to such Demand Resource for the summer period of June through October and May of the Delivery Year, and shall equal the lesser of (i) the sum of the summer Nominated Values of the registrations linked to such Demand Resource or (ii) the sum of the winter Nominated Values of the registrations linked to such Demand Resource for the non-summer period of November through April of the Delivery Year.

K. Compliance is the process utilized to review Provider performance during PJM-initiated Load Management events and Curtailment Service Provider initiated tests. Compliance will be established for each Provider on an event specific basis for the Curtailment Service Provider's Demand Resource Registrations dispatched by the Office of the Interconnection during such event. PJM will establish and communicate reasonable deadlines for the timely submittal of event data to expedite compliance reviews. Compliance reviews will be completed as soon after the event as possible, with the expectation that reviews of a single event will be completed within two months of the end of the month in which the event took place. Curtailment Service Providers are responsible for the submittal of compliance information to PJM for each PJM-initiated event and Curtailment Service Provider initiated test during the compliance period.

Compliance is measured for Market Participant Bonus Performance, as applicable, and Non-Performance Charges. Non-Performance Charges are assessed for the defined obligation period of each Demand Resource as defined in RAA, Article 1, subject to the following requirements:

Compliance is checked on an individual customer basis for Firm Service Level, by comparing actual load during the event to the firm service level. Current load for a statistical sample of end-use customers may be used for compliance for residential non-interval metered registrations in accordance with the PJM Manuals and subject to PJM approval. Curtailment Service Providers must submit actual customer load levels (for the event period) for the compliance report. Compliance for FSL will be based on:

> Summer (June through October and the following May of a Delivery Year)- End use customer's current Delivery Year peak load contribution ("PLC") minus the metered load ("Load") multiplied by the loss factor ("LF"). The calculation is represented by:
>
> (PLC) - (Load *LF)
>
> Winter (November through April of a Delivery Year)– End use customer's Winter Peak Load ("WPL") multiplied by Zonal Winter Weather Adjustment Factor ("ZWWAF") multiplied by LF, minus the metered load ("Load") multiplied by the LF. The calculation is represented by:
>
> (WPL * ZWWAF * LF) – (Load * LF)

Compliance is checked on an individual customer basis for Guaranteed Load Drop. Current load for a statistical sample of end-use customers may be used for compliance for residential non-interval metered registrations in accordance with the PJM Manuals and subject to PJM approval. Guaranteed Load Drop compliance will be based on:

(i) the lesser of (a) comparison load used to best represent what the load would have been if PJM did not declare a Load Management Event or the CSP did not initiate a test as outlined in the PJM Manuals, minus the Load and then multiplied by the LF, or (b) For a summer event, the PLC minus the Load multiplied by the LF. A summer load reduction will only be recognized for capacity compliance if the Load multiplied by the LF is less than the PLC. For a non-summer event, the WPL multiplied the ZWWAF multiplied by LF, minus the Load multiplied by the LF. A non-summer load reduction will only be recognized for capacity compliance if the Load multiplied by the LF is less than the WPL multiplied by the ZWWAF multiplied by LF.

(ii) Curtailment Service Providers must submit actual loads and comparison loads for all hours during the day of the Load Management Event or the Load Management performance test, and for all hours during any other days as required by the Office of the Interconnection to calculate the load reduction. Comparison loads must be developed from the guidelines in the PJM Manuals, and note which method was employed.

(iii) Methodologies for establishing comparison load for Guaranteed Load Drop end-use customers are described in greater detail in Manual M-19, PJM Manual for Load Forecasting and Analysis, at Attachment A: Load Drop Estimate Guidelines.

Load reduction compliance is averaged over the Load Management Event for a Demand Resource Registration linked to a Limited Demand Resource, Extended Summer Demand Resource, or Annual Demand Resource without a Capacity Performance commitment or determined on an hourly basis for a Demand Resource Registration linked to a Base Capacity Demand Resource or Annual Demand Resource with a Capacity Performance commitment, for each FSL and GLD customer dispatched by the Office of the Interconnection for at least 30 minutes of the clock hour (i.e., "partial dispatch compliance hour"). The registered capacity commitment for a Demand Resource Registration without a Base or Capacity Performance commitment for the partial dispatch compliance hour will be prorated based on the number of minutes dispatched during the clock hour and as defined in the Manuals. Curtailment Service Provider may submit 1 minute load data for use in capacity compliance calculations for partial dispatch compliance hours subject to PJM approval and in accordance with the PJM Manuals where: (a) metering meets all Tariff and Manual requirements, (b) 1 minute load data shall be submitted to PJM for all locations on the registration, and (c) 1 minute load data measures energy consumption over the minute. The registered capacity commitment for a Demand Resource Registration with a Base or Capacity Performance commitment is not prorated based on the number of minutes dispatched during the clock hours. The actual hourly load reduction for the hour ending that includes a Performance Assessment Interval(s) is flat-profiled over the set of dispatch intervals in the hour in accordance with the PJM Manuals.

A Demand Resource Registration may not reduce their load below zero (i.e., export energy into the system). No compliance credit will be given for an incremental load drop below zero.

Compliance will be totaled over all dispatched registrations for FSL and GLD customers linked to a committed Limited Demand Resource, Extended Summer Demand Resource, and Annual Demand Resource without a Capacity Performance commitment to determine a net compliance position for the event for each Provider by Compliance Aggregation Area and such net compliance position shall be allocated to the underlying registrations, in accordance with PJM Manuals. Load Management Event deficiencies shall be as further determined in accordance with Tariff, Attachment DD, section 11 and PJM Manuals.

For a Performance Assessment Interval, compliance will be totaled over all dispatched registrations for FSL and GLD customers linked to a Provider's Base Capacity Demand Resource or to an Annual Demand Resource with a Capacity Performance commitment to determine the Actual Performance for such Demand Resource in accordance with Tariff, Attachment DD, section 10A, and PJM Manuals. The Expected Performance for such Demand Resource shall be equal to the Provider's committed capacity on the Demand Resource, adjusted to account for any linked registrations that were not dispatched by PJM. A Provider's Demand Resources' initial Performance Shortfalls shall be netted for all the seller's Demand Resources in the Emergency Action Area to determine a net Emergency Action Area Performance Shortfall which is then allocated to the Capacity Market Seller's Demand Resources in accordance with Tariff, Attachment DD, section 10A, and PJM Manuals.

L. Energy Efficiency Resources

1. An Energy Efficiency Resource is a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during peak summer and winter periods as described herein) reduction in electric energy consumption at the End-Use Customer's retail site that is not reflected in the peak load forecast prepared for the Delivery Year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.

2. An Energy Efficiency Resource may be offered as a Capacity Resource in the Base Residual or Incremental Auctions for any Delivery Year beginning on or after June 1, 2011. No later than 30 days prior to the auction in which the resource is to be offered, the Capacity Market Seller shall submit to the Office of the Interconnection a notice of intent to offer the resource into such auction and a measurement and verification plan. The notice of intent shall include all pertinent project design data, including but not limited to the peak-load contribution of affected customers, a full description of the equipment, device, system or process intended to achieve the load reduction, the load reduction pattern, the project location, the project development timeline, and any other relevant data. Such notice also shall state the seller's proposed Nominated Energy Efficiency Value.

   - For Delivery Years through May 31, 2018 for all Energy Efficiency Resources not committed as a Capacity Performance Resource, the seller's proposed Nominated Energy Efficiency Value shall be the expected average load reduction between the hour ending 15:00 EPT and the hour ending 18:00 EPT during all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday;

   - For the 2018/2019 and 2019/2020 Delivery Years, the seller's proposed Nominated Energy Efficiency Value for any Base Capacity Energy Efficiency

Resource shall be the expected average load reduction between the hour ending 15:00 EPT and the hour ending 18:00 EPT during all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday; and

- For the 2018/2019 Delivery Year and subsequent Delivery Years and for any Annual Energy Efficiency Resource committed as a Capacity Performance Resource for the 2016/2017 and 2017/2018 Delivery Years, the seller's proposed Nominated Energy Efficiency Value for any Annual Energy Efficiency Resources, shall be the expected average load reduction, for all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday, between the hour ending 15:00 EPT and the hour ending 18:00 EPT. In addition, the expected average load reduction for all days from January 1 through February 28, inclusive, of such Delivery Year that is not a weekend or federal holiday, between the hour ending 8:00 EPT and the hour ending 9:00 EPT and between the hour ending 19:00 EPT and the hour ending 20:00 EPT shall not be less than the Nominated Energy Efficiency Value; and

- For the 2020/2021 Delivery Year and subsequent Delivery Years, the seller's proposed Nominated Energy Efficiency Value for any Summer-Period Energy Efficiency Resource shall be the expected average load reduction between the hour ending 15:00 EPT and the hour ending 18:00 EPT during all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday.

The measurement and verification plan shall describe the methods and procedures, consistent with the PJM Manuals, for determining the amount of the load reduction and confirming that such reduction is achieved. The Office of the Interconnection shall determine, upon review of such notice, the Nominated Energy Efficiency Value that may be offered in the Reliability Pricing Model Auction.

3. An Energy Efficiency Resource may be offered with a price offer or as Self-Supply. If an Energy Efficiency Resource clears the auction, it shall receive the applicable Capacity Resource Clearing Price, subject to section 5 below. A Capacity Market Seller offering an Energy Efficiency Resource must comply with all applicable credit requirements as set forth in Tariff, Attachment Q. For Delivery Years through May 31, 2018, or for FRR Capacity Plans for Delivery Years through May 31, 2019, the Unforced Capacity value of an Energy Efficiency Resource offered into an RPM Auction shall be the Nominated Energy Efficiency value times the DR Factor and the Forecast Pool Requirement. For the 2018/2019 Delivery Year and subsequent Delivery Years, or for FRR Capacity Plans for the 2019/2020 Delivery Year and subsequent Delivery Years, the Unforced Capacity value of an Energy Efficiency Resource offered into an RPM

Auction shall be the Nominated Energy Efficiency Value times the Forecast Pool Requirement.

4. An Energy Efficiency Resource that clears an auction for a Delivery Year may be offered in auctions for up to three additional consecutive Delivery Years, but shall not be assured of clearing in any such auction; provided, however, an Energy Efficiency Resource may not be offered for any Delivery Year in which any part of the peak season is beyond the expected life of the equipment, device, system, or process providing the expected load reduction; and provided further that a Capacity Market Seller that offers and clears an Energy Efficiency Resource in a BRA may elect a New Entry Price Adjustment on the same terms as set forth in Tariff, Attachment DD, section 5.14(c).

5. For every Energy Efficiency Resource clearing an RPM Auction for a Delivery Year, the Capacity Market Seller shall submit to the Office of the Interconnection, by no later than 30 days prior to each Auction an updated project status and measurement and verification plan subject to the criteria set forth in the PJM Manuals.

6. For every Energy Efficiency Resource clearing an RPM Auction for a Delivery Year, the Capacity Market Seller shall submit to the Office of the Interconnection, by no later than the start of such Delivery Year, an updated project status and detailed measurement and verification data meeting the standards for precision and accuracy set forth in the PJM Manuals. The final value of the Energy Efficiency Resource during such Delivery Year shall be as determined by the Office of the Interconnection based on the submitted data.

7. The Office of the Interconnection may audit, at the Capacity Market Seller's expense, any Energy Efficiency Resource committed to the PJM Region. The audit may be conducted any time including the Performance Hours of the Delivery Year.

8. For Incremental Auctions conducted for the 2019/2020 and 2020/2021 Delivery Years, and for RPM Auctions for the 2021/2022 Delivery Year and subsequent Delivery Years, if a Relevant Electric Retail Regulatory Authority receives FERC authorization to qualify or prohibit Energy Efficiency Resource participation in a specific area(s) of the PJM Region, the following process applies:

   (a) The Office of the Interconnection will publicly post a reference to the FERC authorization of a Relevant Electric Retail Regulatory Authority order, ordinance or resolution that qualifies or prohibits Energy Efficiency Resource participation, the applicable electric distribution company(ies), and the applicable auction(s) and/or Delivery Year(s).

(b) A Capacity Market Seller that intends to offer or certify Energy Efficiency Resources must identify and itemize all resources that are located in the jurisdiction of a Relevant Electric Retail Regulatory Authority authorized by FERC to qualify or prohibit Energy Efficiency Resource participation within the Zone or LDA, as required, and those outside of the area but within the Zone or LDA, as required.

(c) A Capacity Market Seller that intends to offer or certify Energy Efficiency Resources must identify and itemize all Energy Efficiency Resources to be offered as part of its Energy Efficiency measurement and verification plan and certified post-installation measurement and verification report. The Office of Interconnection will provide a list to the relevant electric distribution company for the specific area(s) to review for compliance with the Relevant Electric Retail Regulatory Authority of Capacity Market Sellers that are:

(i) offering Energy Efficiency Resources in an RPM Auction within two (2) Business Days after the deadline for submitting an energy efficiency measurement and verification plan for such RPM Auction; and

(ii) certifying Energy Efficiency Resources with a Delivery Year post-installation measurement and verification report, within two (2) Business Days of receipt of such Delivery Year post-installation measurement and verification report.The relevant electric distribution company for the specific area(s) shall review for compliance with rules from a Relevant Electric Retail Regulatory Authority authorized by FERC to qualify or prohibit Energy Efficiency Resource.

(d) The relevant electric distribution company for the specific area(s) shall review for compliance with rules from a Relevant Electric Retail Regulatory Authority authorized by FERC to qualify or prohibit Energy Efficiency Resource participation and provide a response to the Office of the Interconnection within five (5) Business Days after receiving the list of Capacity Market Sellers offering Energy Efficiency Resources. The Office of the Interconnection will not allow a Capacity Market Seller to offer or certify Energy Efficiency Resources if an electric distribution company denies such Capacity Market Seller to deliver Energy Efficiency Resources in compliance with rules of a Relevant Electric Retail Regulatory Authority authorized by FERC to qualify or prohibit Energy Efficiency Resource participation.

(9) For Incremental Auctions that will be conducted for the 2019/2020 and 2020/2021 Delivery Years, and for RPM Auctions for the 2021/2022 Delivery

Year and subsequent Delivery Years, a Capacity Market Seller of Energy Efficiency Resources that cannot satisfy its RPM obligations in any Delivery Year due to the prohibition of participation by a Relevant Electric Retail Regulatory Authority authorized by FERC to prohibit participation of such resources may be relieved of its Capacity Resource Deficiency Charge by notifying the Office of the Interconnection by no later than seven (7) calendar days prior to the posting of the planning parameters for the Third Incremental Auction of that Delivery Year. After providing such notice, the affected Capacity Market Seller may elect to be relieved of its RPM commitment, and shall not be required to obtain replacement capacity for the resource, and no charges shall be assessed by the Office of the Interconnection for the Capacity Market Seller's deficiency in satisfying its RPM obligation for the resource for such Delivery Year. In such case, however, the Capacity Market Seller shall not be entitled to, nor be paid, any RPM revenues for such resource for that Delivery Year. The Office of the Interconnection will apply corresponding adjustments to the quantity of Buy Bids or Sell Offers in the Incremental Auctions for such Delivery Years in accordance with Tariff, Attachment DD, sections 5.12(b)(ii) and 5.12(b)(iii).

Section of the
PJM Reliability Assurance Agreement

(Marked / Redline Format)

SCHEDULE 6

PROCEDURES FOR DEMAND RESOURCES AND ENERGY EFFICIENCY

A. Parties can partially or wholly offset the amounts payable for the Locational Reliability Charge with Demand Resources that are operated under the direction of the Office of the Interconnection. FRR Entities may reduce their capacity obligations with Demand Resources that are operated under the direction of the Office of the Interconnection and detailed in such entity's FRR Capacity Plan. Demand Resources qualifying under the criteria set forth below may be offered for sale or designated as Self-Supply in the Base Residual Auction, included in an FRR Capacity Plan, or offered for sale in any Incremental Auction, for any Delivery Year for which such resource qualifies. Qualified Demand Resources generally fall in one of two categories, i.e., Guaranteed Load Drop or Firm Service Level, as further specified in section G below and the PJM Manuals. Qualified Demand Resources may be provided by a Curtailment Service Provider, notwithstanding that such Curtailment Service Provider is not a Party to this Agreement. Such Curtailment Service Providers must satisfy the requirements hereof and the PJM Manuals.

1. A Party must formally notify, in accordance with the requirements of the PJM Manuals and section F hereof, as applicable, the Office of the Interconnection of the Demand Resource Registration that it is placing under the direction of the Office of the Interconnection. A Party must further notify the Office of the Interconnection whether the Demand Resource Registration is linked to a Limited Demand Resource, an Extended Summer Demand Resource, a Base Capacity Demand Resource, a Summer-Period Demand Resource or an Annual Demand Resource.

2. A Demand Resource Registration must achieve its full load reduction within the following time period:

(a) For the 2015/2016 Delivery Year and subsequent Delivery Years, a Demand Resource Registration must be able to fully respond to a Load Management Event within 30 minutes of notification from the Office of the Interconnection. This default 30 minute prior notification shall apply unless a Curtailment Service Provider obtains an exception from the Office of the Interconnection due to physical operational limitations that prevent the Demand Resource Registration from reducing load within that timeframe. In such case, the Curtailment Service Provider shall submit a request for an exception to the 30 minute prior notification requirement to the Office of the Interconnection, at the time the Registration Form for that Demand Resource Registration is submitted in accordance with Tariff, Attachment K-Appendix. The only alternative notification times that the Office of Interconnection will permit, upon approval of an exception request, are 60 minutes and 120 minutes prior to a Load Management Event. The Curtailment Service Provider shall indicate in writing, in the appropriate application, that it seeks an exception to permit a prior notification time of 60 minutes or 120 minutes, and the reason(s) for the requested exception. A Curtailment Service

Provider shall not submit a request for an exception to the default 30 minute notification period unless it has done its due diligence to confirm that the Demand Resource Registration is physically incapable of responding within that timeframe based on one or more of the reasons set forth below and as may be further defined in the PJM Manuals and has obtained detailed data and documentation to support this determination.

In order to establish that a Demand Resource Registration is reasonably expected to be physically unable to reduce load in that timeframe, the Curtailment Service Provider that submitted the Demand Resource Registration must demonstrate that:

(i) The manufacturing processes for the Demand Resource Registration require gradual reduction to avoid damaging major industrial equipment used in the manufacturing process, or damage to the product generated or feedstock used in the manufacturing process;

(ii) Transfer of load to back-up generation requires time-intensive manual process taking more than 30 minutes;

(iii) On-site safety concerns prevent location from implementing reduction plan in less than 30 minutes; or,

(iv) The Demand Resource Registration is comprised of mass market residential customers or Small Commercial Customers which collectively cannot be notified of a Load Management Event within a 30-minute timeframe due to unavoidable communications latency, in which case the requested notification time shall be no longer than 120 minutes.

The Office of the Interconnection may request data and documentation from the Curtailment Service Provider and such Curtailment Service Provider shall provide to the Office of the Interconnection within three (3) Business Days of a request therefor, a copy of all of the data and documentation supporting the exception request. Failure to provide a timely response to such request shall cause the exception to terminate the following Operating Day.

At its sole option and discretion, the Office of the Interconnection may review the data and documentation provided by the Curtailment Service Provider to determine if the Demand Resource Registration has met one or more of the criteria above. The Office of the Interconnection will notify the Curtailment Service Provider in writing of its determination by no later than ten (10) Business Days after receipt of the data and documentation.

The Curtailment Service Provider shall provide written notification to the Office of the Interconnection of a material change to the facts that supported its exception request within three (3) Business Days of becoming aware of such material change in facts, and, if the Office of Interconnection determines that the physical limitation criteria above are no longer being met, the Demand Resource Registration shall be subject to the default notification period of 30 minutes immediately upon such determination.

3. The initiation of load reduction, upon the request of the Office of the Interconnection, must be within the authority of the dispatchers of the Party. No additional approvals should be required.

4. The initiation of load reduction upon the request of the Office of the Interconnection is considered a pre-emergency or emergency action and must be implementable prior to a voltage reduction.

5. A Curtailment Service Provider intending to offer for sale or designate for self-supply, a Demand Resource in any RPM Auction, or intending to include a Demand Resource in any FRR Capacity Plan must demonstrate, to PJM's satisfaction, that such resource shall have the capability to provide a reduction in demand, or otherwise control load, on or before the start of the Delivery Year for which such resource is committed. As part of such demonstration, each such Curtailment Service Provider shall submit a Demand Resource Sell Offer Plan in accordance with the standards and procedures set forth in RAA, Schedule 6, section A-1; RAA, Schedule 8.1 (as to FRR Capacity Plans) and the PJM Manuals, no later than 30~~15 Business D~~days prior to, as applicable, the RPM Auction in which such resource is to be offered, or the deadline for submission of the FRR Capacity Plan in which such resource is to be included. PJM may verify the Curtailment Service Provider's adherence to the Demand Resource Sell Offer Plan at any time. A Curtailment Service Provider with a PJM-approved Demand Resource Sell Offer Plan will be permitted to offer up to the approved Demand Resource quantity into the subject RPM Auction or include such resource in its FRR Capacity Plan.

6. Selection of a Demand Resource in an RPM Auction results in commitment of capacity to the PJM Region. Demand Resources that are so committed must be linked to registrations participating in the Full Program Option or Capacity Only Option of the Emergency Load Response and Pre-Emergency Load Response Program and thus available for dispatch during PJM-declared pre-emergency events and emergency events.

A-1. A Demand Resource Sell Offer Plan shall consist of a completed template document in the form posted on the PJM website, requiring the information set forth below and in the PJM Manuals, and a Demand Resource Officer Certification Form signed by an officer of the Demand Resource Provider that is duly authorized to provide such a certification. The Demand Resource Sell Offer Plan must provide information that supports the Demand Resource Provider's intended Demand Resource Sell Offers and demonstrates that the Demand Resources are being offered with the intention that the MW quantity that clears the auction is reasonably expected to be physically delivered through Demand Resource registrations for the relevant Delivery Year. The Demand Resource Sell Offer Plan shall include all Existing Demand Resources and all Planned Demand Resources that the Demand Resource Provider intends to offer into an RPM Auction or include in an FRR Capacity Plan.

1. Demand Resource Sell Offer Plan Template. The Demand Resource Sell Offer Plan template, in the form provided on the PJM website, shall require the

Demand Resource Provider to provide the following information and such other information as specified in the PJM Manuals:

(a) Summary Information. The completed template shall include the Demand Resource Provider's company name, contact information, and the Nominated DR Value in ICAP MWs by Zone/sub-Zone that the Demand Resource Provider intends to offer, stated separately for Existing Demand Resources and Planned Demand Resources. The total Nominated DR Value in MWs for each Zone/sub-Zone shall be the sum of the Nominated DR Value of Existing Demand Resources and the Nominated DR Value of Planned Demand Resources, and shall be the maximum MW amount the Provider intends to offer in the RPM Auction for the indicated Zone/sub-Zone, provided that nothing herein shall preclude the Demand Resource Provider from offering in the auction a lesser amount than the total Nominated DR Value shown in its Demand Resource Sell Offer Plan.

(b) Existing Demand Resources. The Demand Resource Provider shall identify all Existing Demand Resources by identifying end-use customer sites that are currently registered with PJM (even if not registered by such Demand Resource Provider) and that the Demand Resource Provider reasonably expects to have under a contract to reduce load based on PJM dispatch instructions by the start of the auction Delivery Year.

(c) Planned Demand Resources. The Demand Resource Provider shall provide the details of, and key assumptions underlying, the Planned Demand Resource quantities (i.e., all Demand Resource quantities in excess of Existing Demand Resource quantities) contained in the Demand Resource Sell Offer Plan, including:

(i) key program attributes and assumptions used to develop the Planned Demand Resource quantities, including, but not limited to, discussion of:

- method(s) of achieving load reduction at customer site(s);
- equipment to be controlled or installed at customer site(s), if any;
- plan and ability to acquire customers;
- types of customer targeted;
- support of market potential and market share for the target customer base, with adjustments for Existing Demand Resource customers within this market and the potential for other Demand Resource Providers targeting the same customers; and
- assumptions regarding regulatory approval of program(s), if applicable.

(ii) Zone/sub-Zone information by end-use customer segment for all Nominated DR Values for which an end-use customer site is not identified, to include the number in each segment of end-use customers expected to be registered for the subject Delivery Year, the average Peak Load Contribution per end-use customer for such segment, and the average Nominated DR Value per customer for such segment. End-use customer segments may include residential, commercial, small industrial, medium industrial, and large industrial, as identified and defined in the PJM Manuals, provided that nothing herein or in the Manuals shall preclude the Provider from identifying more specific customer segments within the commercial and industrial categories, if known.

(iii) Information by end-use customer site to the extent required by subsection A-1(1)(c)(iv) or, if not required by such subsection, to the extent known at the time of the submittal of the Demand Resource Sell Offer Plan, to include: customer EDC account number (if known), customer name, customer premise address, Zone/sub-Zone in which the customer is located, end-use customer segment, current Peak Load Contribution value (or an estimate if actual value not known) and an estimate of expected Peak Load Contribution for the subject Delivery Year, and an estimated Nominated DR Value.

(iv) End-use customer site-specific information shall be required for any Zones or sub-Zones identified by PJM pursuant to this subsection for the portion, if any, of a Demand Resource Provider's intended offer in such Zones or sub-Zones that exceeds a Sell Offer threshold determined pursuant to this subsection, as any such excess quantity under such conditions should reflect Planned Demand Resources from end-use customer sites that the Provider has a high degree of certainty it will physically deliver for the subject Delivery Year. In accordance with the procedures in subsection A-1(3) below, PJM shall identify, as requiring site-specific information, all Zones and sub-Zones that comprise any LDA group (from a list of LDA groups stated in the PJM Manuals) in which [the quantity of cleared Demand Resources from the most recent Base Residual Auction] plus [the quantity of Demand Resources included in FRR Capacity Plans for the Delivery Year addressed by the most recent Base Residual Auction] in any Zone or sub-Zone of such LDA group exceeds the greater of:

- the maximum Demand Resources quantity registered with PJM for such Zone for any Delivery Year from the current (at time of plan submission) Delivery Year and the two preceding Delivery Years; and

- the potential Demand Resource quantity for such Zone estimated by PJM based on an independent published assessment of demand response potential that is reasonably applicable to such Zone, as identified in the PJM Manuals.

For each such Zone and sub-Zone, the Sell Offer threshold for each Demand Resource Provider shall be the higher of:

- the Demand Resource Provider's maximum Demand Resource quantity registered with PJM for such Zone/sub-Zone over the current Delivery Year (at the time of plan submission) and two preceding Delivery Years;

- the Demand Resource Provider's maximum for any single Delivery Year of [such provider's cleared Demand Resource quantity] plus [such provider's quantity of Demand Resources included in FRR Capacity Plans] from the three forward Delivery Years addressed by the three most recent Base Residual Auctions for such Zone/sub-Zone; and

- 10 MW.

(d) Schedule. The Demand Resource Provider shall provide an approximate timeline for procuring end-use customer sites as needed to physically deliver the total Nominated DR Value (for both Existing Demand Resources and Planned Demand Resources) by Zone/sub-Zone in the Demand Resource Sell Offer Plan. The Demand Resource Provider must specify the cumulative number of customers and the cumulative Nominated DR Value associated with each end-use customer segment within each Zone/sub-Zone that the Demand Resource Provider expects (at the time of plan submission) to have under contract as of June 1 each year between the time of the auction and the subject Delivery Year.

(e) Minimum Offer Price Rule for Demand Resources. The Demand Resource Provider shall certify whether or not the Existing Demand Resource end use customer site(s) and Planned Demand Resource is entitled to a State Subsidy. Such certifications shall be made separately for end-use customer locations that are entitled to receive State Subsidy and those that are not, in accordance with the procedures provided in the PJM Manuals, to ensure the accurate application of the Minimum Offer Price Rules. Sell Offers for Demand Resources that are Capacity Resources with State Subsidy shall be offered separately for load-backed Demand Resources and generation-backed Demand Resources, unless the Capacity Market Seller for such Capacity Resource with State Subsidy elects the competitive exemption pursuant to Tariff, Attachment DD, section 5.14(h).

2. Demand Resource Officer Certification Form. Each Demand Resource Sell Offer Plan must include a Demand Resource Officer Certification, signed by an officer of the Demand Resource Provider that is duly authorized to provide such a certification, in the form shown in the PJM Manuals, which form shall include the following certifications:

(a) that the signing officer has reviewed the Demand Resource Sell Offer Plan and the information supplied to PJM in support of the Plan is true and correct as of the date of the certification; and

(b) that the Demand Resource Provider is submitting the Plan with the reasonable expectation, based upon its analyses as of the date of the certification, to physically deliver all megawatts that clear the RPM Auction through Demand Resource registrations by the specified Delivery Year.

As set forth in the form provided in the PJM Manuals, the certification shall specify that it does not in any way abridge, expand, or otherwise modify the current provisions of the PJM Tariff, Operating Agreement and/or RAA, or the Demand Resource Provider's rights and obligations thereunder, including the Demand Resource Provider's ability to adjust capacity obligations through participation in PJM incremental auctions and bilateral transactions.

3. Procedures. No later than December 1 prior to the Base Residual Auction for a Delivery Year, PJM shall post to the PJM website a list of Zones and sub-Zones, if any, for which end-use customer site-specific information shall be required under the conditions specified in subsection A-1(1)(c)(iv) above for all RPM Auctions conducted for such Delivery Year. Once so identified, a Zone or sub-Zone shall remain on the list for future Delivery Years until the threshold determined under subsection A-1(1)(c)(iv) above is not exceeded for three consecutive Delivery Years. No later than 30~~15 Business D~~days prior to the RPM Auction in which a Demand Resource Provider intends to offer a Demand Resource, the Demand Resource Provider shall submit to PJM a completed Demand Resource Sell Offer Plan template and a Demand Resource Officer Certification Form signed by a duly authorized officer of the Provider. PJM will review all submitted DR Sell Offer Plans. No later than 10 Business Days prior to the subject RPM Auction, PJM shall notify any Demand Resource Providers that have identified the same end-use customer site(s) in their respective DR Sell Offer Plans for the same Delivery Year. In such event, the MWs associated with such site(s) will not be approved for inclusion in a Sell Offer in an RPM Auction by any of the Demand Resource Providers, unless a Demand Resource Provider provides a letter of support from the end-use customer indicating that it is likely to execute a contract with that Demand Resource Provider for the relevant Delivery Year, or provides other comparable evidence of likely commitment. Such letter of support or other supporting evidence must be provided to PJM no later than 7 Business Days prior to the subject RPM Auction. If an end-use customer

provides letters of support for the same site for the same Delivery Year to multiple Demand Resource Providers, the MWs associated with such end-use customer site shall not be approved as a Demand Resource for any of the Demand Resource Providers. No later than 5 Business Days prior to the subject RPM Auction, PJM will notify each Demand Resource Provider of the approved Demand Resource quantity, by Zone/sub-Zone, that such Demand Resource Provider is permitted to offer into such RPM Auction.

B. The Unforced Capacity value of a Demand Resource will be determined as:

for the Delivery Years through May 31, 2018, or for FRR Capacity Plans for Delivery Years through May 31, 2019, the product of the Nominated Value of the Demand Resource, times the DR Factor, times the Forecast Pool Requirement, and for the 2018/2019 Delivery Year and subsequent Delivery Years, or for FRR Capacity Plans for the 2019/2020 Delivery Year and subsequent Delivery Years, the product of the Nominated Value of the Demand Resource times the Forecast Pool Requirement. Nominated Values shall be determined and reviewed in accordance with sections I and J, respectively, and the PJM Manuals. The DR Factor is a factor established by the PJM Board with the advice of the Members Committee to reflect the increase in the peak load carrying capability in the PJM Region due to Demand Resources. Peak load carrying capability is defined to be the peak load that the PJM Region is able to serve at the loss of load expectation defined in the Reliability Principles and Standards. The DR Factor is the increase in the peak load carrying capability in the PJM Region due to Demand Resources, divided by the total Nominated Value of Demand Resources in the PJM Region. The DR Factor will be determined using an analytical program that uses a probabilistic approach to determine reliability. The determination of the DR Factor will consider the reliability of Demand Resources, the number of interruptions, and the total amount of load reduction.

C. Demand Resources offered and cleared in a Base Residual or Incremental Auction shall receive the corresponding Capacity Resource Clearing Price as determined in such auction, in accordance with Tariff, Attachment DD. For Delivery Years beginning with the Delivery Year that commences on June 1, 2013, any Demand Resources located in a Zone with multiple LDAs shall receive the Capacity Resource Clearing Price applicable to the location of such resource within such Zone, as identified in such resource's offer. Further, the Curtailment Service Provider shall register its resource in the same location within the Zone as specified in its cleared sell offer, and shall be subject to deficiency charges under Tariff, Attachment DD to the extent it fails to provide the resource in such location consistent with its cleared offer.

D. The Party, Electric Distributor, or Curtailment Service Provider that establishes a contractual relationship (by contract or tariff rate) with a customer for load reductions is entitled to receive the compensation specified in section C for a committed Demand Resource, notwithstanding that such provider is not the customer's energy supplier.

E. Any Party hereto shall demonstrate that its Demand Resources performed during periods when load management procedures were invoked by the Office of the Interconnection. The Office of the Interconnection shall adopt and maintain rules and procedures for verifying the performance of such resources, as set forth in section K hereof and the PJM Manuals. In addition, committed Demand Resources that do not comply with the directions of the Office of the Interconnection to reduce load during an emergency shall be subject to the penalty charge set forth in Tariff, Attachment DD.

F. Parties may elect to place Demand Resources associated with Behind The Meter Generation under the direction of the Office of the Interconnection for a Delivery Year by submitting a Sell Offer for such resource (as Self Supply, or with an offer price) in the Base Residual Auction for such Delivery Year. This election shall remain in effect for the entirety of such Delivery Year. In the event such an election is made, such Behind The Meter Generation will not be netted from load for the purposes of calculating the Daily Unforced Capacity Obligations under this Agreement.

G. PJM measures Demand Resource Registrations in the following ways:

Firm Service Level (FSL) – Load management achieved by an end-use customer reducing its load to a pre-determined level (the Firm Service Level), upon notification from the Curtailment Service Provider’s market operations center or its agent.

Guaranteed Load Drop (GLD) – Load management achieved by an end-use customer reducing its load by a pre-determined amount (the Guaranteed Load Drop), upon notification from the Curtailment Service Provider’s market operations center or its agent. Typically, the load reduction is achieved through running customer-owned backup generators, or by shutting down process equipment.

H. Each Curtailment Service Provider must satisfy (or contract with another LSE, Curtailment Service Provider, or electric distribution company to provide) the following requirements:

- A point of contact with appropriate backup to ensure single call notification from PJM and timely execution of the notification process;

- Supplemental status reports, detailing Demand Resources available, as requested by PJM;

- Entry of customer-specific Demand Resource Registration information, for planning and verification purposes, into the designated PJM electronic system.

- Customer-specific compliance and verification information for each PJM-initiated Demand Resource event or Provider initiated test event, as well as aggregated Provider load drop data for Provider-initiated events, in accordance with established reporting guidelines.

● Load drop estimates for all Load Management events and test events, prepared in accordance with the PJM Manuals.

I. The Nominated Values (summer, winter or annual) for each Demand Resource Registration shall be determined consistent with the process described below.

The summer Nominated Value for Firm Service Level customer(s) on a registration will be based on the peak load contribution for the customer(s), as typically determined by the 5CP methodology utilized by the electric distribution company to determine ICAP obligation values. The summer Nominated Value for a registration shall equal the total peak load contribution for the customers on the registration minus the summer Firm Service Level multiplied by the loss factor. The winter Nominated Value for Firm Service Level customer(s) on a registration shall equal the total Winter Peak Load for customers on the registration multiplied by Zonal Winter Weather Adjustment Factor minus winter Firm Service level and then the result is multiplied by the loss factor. The annual Nominated Value for or Firm Service Level customer(s) on a registration shall equal the lesser of i) summer Nominated Value or ii) winter Nominated Value. Effective with the 2019/2020 Delivery Year, an annual Nominated Value for a registration is no longer calculated.

The summer Nominated Value for a Guaranteed Load Drop customer on a registrationshall equal the summer guaranteed load drop amount, adjusted for system losses and shall not exceed the customer's Peak Load Contribution, as established by the customer's contract with the Curtailment Service Provider. The winter Nominated Value for a Guaranteed Load Drop customer on a registration shall be the winter guaranteed load drop amount, adjusted for system losses, and shall not exceed the customer's Winter Peak Load multiplied by Zonal Winter Weather Adjustment Factor multiplied by the loss factor, as established by the customer's contract with the Curtailment Service Provider. The annual Nominated Value for a Guaranteed Load Drop customer on a registration shall be the lesser of the i) summer Nominated Value or ii) winter Nominated Value. Effective with the 2019/2020 Delivery Year, an annual Nominated Value for a registration is no longer calculated.

Customer-specific Demand Resource Registration information (EDC account number, peak load contribution, Winter Peak Load, notification period, etc.) will be entered into the designated PJM electronic system to establish nominated values. Each Demand Resource Registration should be linked to a Demand Resource. Additional data may be required, as defined in sections J and K and the PJM Manuals.

J. Nominated Values shall be reviewed based on documentation of customer-specific data and Demand Resource Registration information, to verify the amount of load management available and to set a summer, winter, or annual Nominated Value. Data is provided by both the zone EDC and the Curtailment Service Provider in the designated PJM electronic system, and must include the EDC meter number or other unique customer identifier, Peak Load Contribution (5CP), Winter Peak Load, contract firm service level or guaranteed load drop values, applicable loss factor, zone/area location of the load drop, number of active participants, etc. Such data must be uploaded and approved prior to the first day of the Delivery Year for which such Demand Resource Registration is effective. Curtailment Service Providers must provide this information concurrently to host EDCs.

For Firm Service Level and Guaranteed Load Drop customers, the 5CP values, for the zone and affected customers, will be adjusted to reflect an "unrestricted" peak for a zone, based on information provided by the Curtailment Service Provider. Load drop levels shall be estimated in accordance with guidelines in the PJM Manuals.

The daily Nominated Value for the Delivery Year for a Limited Demand Resource, Extended Summer Demand Resource, Base Capacity Demand Resource, and Annual Demand Resource without a Capacity Performance commitment shall equal the sum of the summer Nominated Values of the registrations linked to such Demand Resource. For the 2017/2018 and 2018/2019 Delivery Years, the daily Nominated Value for the Delivery Year for an Annual Demand Resource with a Capacity Performance commitment shall equal the sum of the annual Nominated Values of the registrations linked to such Demand Resource. For the 2019/2020 Delivery Year, the daily Nominated Value for the Delivery Year for an Annual Demand Resource with a Capacity Performance commitment shall equal the lesser of (i) the sum of the summer Nominated Values of the registrations linked to such Demand Resource or (ii) the sum of the winter Nominated Values of the registrations linked to such Demand Resource. Effective with the 2020/2021 Delivery Year, the daily Nominated Value of a Demand Resource with a Capacity Performance commitment (which may consist of an Annual Demand Resource with a Capacity Performance commitment and/or Summer Period Demand Resource with a Capacity Performance commitment) shall equal the sum of the summer Nominated Values of the registrations linked to such Demand Resource for the summer period of June through October and May of the Delivery Year, and shall equal the lesser of (i) the sum of the summer Nominated Values of the registrations linked to such Demand Resource or (ii) the sum of the winter Nominated Values of the registrations linked to such Demand Resource for the non-summer period of November through April of the Delivery Year.

K. Compliance is the process utilized to review Provider performance during PJM-initiated Load Management events and Curtailment Service Provider initiated tests. Compliance will be established for each Provider on an event specific basis for the Curtailment Service Provider's Demand Resource Registrations dispatched by the Office of the Interconnection during such event. PJM will establish and communicate reasonable deadlines for the timely submittal of event data to expedite compliance reviews. Compliance reviews will be completed as soon after the event as possible, with the expectation that reviews of a single event will be completed within two months of the end of the month in which the event took place. Curtailment Service Providers are responsible for the submittal of compliance information to PJM for each PJM-initiated event and Curtailment Service Provider initiated test during the compliance period.

Compliance is measured for Market Participant Bonus Performance, as applicable, and Non-Performance Charges. Non-Performance Charges are assessed for the defined obligation period of each Demand Resource as defined in RAA, Article 1, subject to the following requirements:

Compliance is checked on an individual customer basis for Firm Service Level, by comparing actual load during the event to the firm service level. Current load for a statistical sample of end-use customers may be used for compliance for residential non-interval metered registrations in accordance with the PJM Manuals and subject to PJM approval. Curtailment Service Providers must submit actual customer load levels (for the event period) for the compliance report. Compliance for FSL will be based on:

> Summer (June through October and the following May of a Delivery Year)- End use customer's current Delivery Year peak load contribution ("PLC") minus the metered load ("Load") multiplied by the loss factor ("LF"). The calculation is represented by:
>
> (PLC) - (Load *LF)
>
> Winter (November through April of a Delivery Year)– End use customer's Winter Peak Load ("WPL") multiplied by Zonal Winter Weather Adjustment Factor ("ZWWAF") multiplied by LF, minus the metered load ("Load") multiplied by the LF. The calculation is represented by:
>
> (WPL * ZWWAF * LF) – (Load * LF)

Compliance is checked on an individual customer basis for Guaranteed Load Drop. Current load for a statistical sample of end-use customers may be used for compliance for residential non-interval metered registrations in accordance with the PJM Manuals and subject to PJM approval. Guaranteed Load Drop compliance will be based on:

(i) the lesser of (a) comparison load used to best represent what the load would have been if PJM did not declare a Load Management Event or the CSP did not initiate a test as outlined in the PJM Manuals, minus the Load and then multiplied by the LF, or (b) For a summer event, the PLC minus the Load multiplied by the LF. A summer load reduction will only be recognized for capacity compliance if the Load multiplied by the LF is less than the PLC. For a non-summer event, the WPL multiplied the ZWWAF multiplied by LF, minus the Load multiplied by the LF. A non-summer load reduction will only be recognized for capacity compliance if the Load multiplied by the LF is less than the WPL multiplied by the ZWWAF multiplied by LF.

(ii) Curtailment Service Providers must submit actual loads and comparison loads for all hours during the day of the Load Management Event or the Load Management performance test, and for all hours during any other days as required by the Office of the Interconnection to calculate the load reduction. Comparison loads must be developed from the guidelines in the PJM Manuals, and note which method was employed.

(iii) Methodologies for establishing comparison load for Guaranteed Load Drop end-use customers are described in greater detail in Manual M-19, PJM Manual for Load Forecasting and Analysis, at Attachment A: Load Drop Estimate Guidelines.

Load reduction compliance is averaged over the Load Management Event for a Demand Resource Registration linked to a Limited Demand Resource, Extended Summer Demand Resource, or Annual Demand Resource without a Capacity Performance commitment or determined on an hourly basis for a Demand Resource Registration linked to a Base Capacity Demand Resource or Annual Demand Resource with a Capacity Performance commitment, for each FSL and GLD customer dispatched by the Office of the Interconnection for at least 30 minutes of the clock hour (i.e., "partial dispatch compliance hour"). The registered capacity commitment for a Demand Resource Registration without a Base or Capacity Performance commitment for the partial dispatch compliance hour will be prorated based on the number of minutes dispatched during the clock hour and as defined in the Manuals. Curtailment Service Provider may submit 1 minute load data for use in capacity compliance calculations for partial dispatch compliance hours subject to PJM approval and in accordance with the PJM Manuals where: (a) metering meets all Tariff and Manual requirements, (b) 1 minute load data shall be submitted to PJM for all locations on the registration, and (c) 1 minute load data measures energy consumption over the minute. The registered capacity commitment for a Demand Resource Registration with a Base or Capacity Performance commitment is not prorated based on the number of minutes dispatched during the clock hours. The actual hourly load reduction for the hour ending that includes a Performance Assessment Interval(s) is flat-profiled over the set of dispatch intervals in the hour in accordance with the PJM Manuals.

A Demand Resource Registration may not reduce their load below zero (i.e., export energy into the system). No compliance credit will be given for an incremental load drop below zero.

Compliance will be totaled over all dispatched registrations for FSL and GLD customers linked to a committed Limited Demand Resource, Extended Summer Demand Resource, and Annual Demand Resource without a Capacity Performance commitment to determine a net compliance position for the event for each Provider by Compliance Aggregation Area and such net compliance position shall be allocated to the underlying registrations, in accordance with PJM Manuals. Load Management Event deficiencies shall be as further determined in accordance with Tariff, Attachment DD, section 11 and PJM Manuals.

For a Performance Assessment Interval, compliance will be totaled over all dispatched registrations for FSL and GLD customers linked to a Provider's Base Capacity Demand Resource or to an Annual Demand Resource with a Capacity Performance commitment to determine the Actual Performance for such Demand Resource in accordance with Tariff, Attachment DD, section 10A, and PJM Manuals. The Expected Performance for such Demand Resource shall be equal to the Provider's committed capacity on the Demand Resource, adjusted to account for any linked registrations that were not dispatched by PJM. A Provider's Demand Resources' initial Performance Shortfalls shall be netted for all the seller's Demand Resources in the Emergency Action Area to determine a net Emergency Action Area Performance Shortfall which is then allocated to the Capacity Market Seller's Demand Resources in accordance with Tariff, Attachment DD, section 10A, and PJM Manuals.

L. Energy Efficiency Resources

1. An Energy Efficiency Resource is a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during peak summer and winter periods as described herein) reduction in electric energy consumption at the End-Use Customer's retail site that is not reflected in the peak load forecast prepared for the Delivery Year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.

2. An Energy Efficiency Resource may be offered as a Capacity Resource in the Base Residual or Incremental Auctions for any Delivery Year beginning on or after June 1, 2011. No later than 30 days prior to the auction in which the resource is to be offered, the Capacity Market Seller shall submit to the Office of the Interconnection a notice of intent to offer the resource into such auction and a measurement and verification plan. The notice of intent shall include all pertinent project design data, including but not limited to the peak-load contribution of affected customers, a full description of the equipment, device, system or process intended to achieve the load reduction, the load reduction pattern, the project location, the project development timeline, and any other relevant data. Such notice also shall state the seller's proposed Nominated Energy Efficiency Value.

   - For Delivery Years through May 31, 2018 for all Energy Efficiency Resources not committed as a Capacity Performance Resource, the seller's proposed Nominated Energy Efficiency Value shall be the expected average load reduction between the hour ending 15:00 EPT and the hour ending 18:00 EPT during all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday;

   - For the 2018/2019 and 2019/2020 Delivery Years, the seller's proposed Nominated Energy Efficiency Value for any Base Capacity Energy Efficiency Resource shall be the expected average load reduction between the hour ending 15:00 EPT and the hour ending 18:00 EPT during all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday; and

- For the 2018/2019 Delivery Year and subsequent Delivery Years and for any Annual Energy Efficiency Resource committed as a Capacity Performance Resource for the 2016/2017 and 2017/2018 Delivery Years, the seller's proposed Nominated Energy Efficiency Value for any Annual Energy Efficiency Resources, shall be the expected average load reduction, for all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday, between the hour ending 15:00 EPT and the hour ending 18:00 EPT. In addition, the expected average load reduction for all days from January 1 through February 28, inclusive, of such Delivery Year that is not a weekend or federal holiday, between the hour ending 8:00 EPT and the hour ending 9:00 EPT and between the hour ending 19:00 EPT and the hour ending 20:00 EPT shall not be less than the Nominated Energy Efficiency Value; and

- For the 2020/2021 Delivery Year and subsequent Delivery Years, the seller's proposed Nominated Energy Efficiency Value for any Summer-Period Energy Efficiency Resource shall be the expected average load reduction between the hour ending 15:00 EPT and the hour ending 18:00 EPT during all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday.

  The measurement and verification plan shall describe the methods and procedures, consistent with the PJM Manuals, for determining the amount of the load reduction and confirming that such reduction is achieved. The Office of the Interconnection shall determine, upon review of such notice, the Nominated Energy Efficiency Value that may be offered in the Reliability Pricing Model Auction.

3. An Energy Efficiency Resource may be offered with a price offer or as Self-Supply. If an Energy Efficiency Resource clears the auction, it shall receive the applicable Capacity Resource Clearing Price, subject to section 5 below. A Capacity Market Seller offering an Energy Efficiency Resource must comply with all applicable credit requirements as set forth in Tariff, Attachment Q. For Delivery Years through May 31, 2018, or for FRR Capacity Plans for Delivery Years through May 31, 2019, the Unforced Capacity value of an Energy Efficiency Resource offered into an RPM Auction shall be the Nominated Energy Efficiency value times the DR Factor and the Forecast Pool Requirement. For the 2018/2019 Delivery Year and subsequent Delivery Years, or for FRR Capacity Plans for the 2019/2020 Delivery Year and subsequent Delivery Years, the Unforced Capacity value of an Energy Efficiency Resource offered into an RPM Auction shall be the Nominated Energy Efficiency Value times the Forecast Pool Requirement.

4. An Energy Efficiency Resource that clears an auction for a Delivery Year may be offered in auctions for up to three additional consecutive Delivery Years, but shall

not be assured of clearing in any such auction; provided, however, an Energy Efficiency Resource may not be offered for any Delivery Year in which any part of the peak season is beyond the expected life of the equipment, device, system, or process providing the expected load reduction; and provided further that a Capacity Market Seller that offers and clears an Energy Efficiency Resource in a BRA may elect a New Entry Price Adjustment on the same terms as set forth in Tariff, Attachment DD, section 5.14(c).

5. For every Energy Efficiency Resource clearing an RPM Auction for a Delivery Year, the Capacity Market Seller shall submit to the Office of the Interconnection, by no later than 30 days prior to each Auction an updated project status and measurement and verification plan subject to the criteria set forth in the PJM Manuals.

6. For every Energy Efficiency Resource clearing an RPM Auction for a Delivery Year, the Capacity Market Seller shall submit to the Office of the Interconnection, by no later than the start of such Delivery Year, an updated project status and detailed measurement and verification data meeting the standards for precision and accuracy set forth in the PJM Manuals. The final value of the Energy Efficiency Resource during such Delivery Year shall be as determined by the Office of the Interconnection based on the submitted data.

7. The Office of the Interconnection may audit, at the Capacity Market Seller's expense, any Energy Efficiency Resource committed to the PJM Region. The audit may be conducted any time including the Performance Hours of the Delivery Year.

8. For Incremental Auctions conducted for the 2019/2020 and 2020/2021 Delivery Years, and for RPM Auctions for the 2021/2022 Delivery Year and subsequent Delivery Years, if a Relevant Electric Retail Regulatory Authority receives FERC authorization to qualify or prohibit Energy Efficiency Resource participation in a specific area(s) of the PJM Region, the following process applies:

(a) The Office of the Interconnection will publicly post a reference to the FERC authorization of a Relevant Electric Retail Regulatory Authority order, ordinance or resolution that qualifies or prohibits Energy Efficiency Resource participation, the applicable electric distribution company(ies), and the applicable auction(s) and/or Delivery Year(s).

(b) A Capacity Market Seller that intends to offer or certify Energy Efficiency Resources must identify and itemize all resources that are located in the jurisdiction of a Relevant Electric Retail Regulatory Authority authorized by FERC to qualify or prohibit Energy Efficiency Resource participation within the

Zone or LDA, as required, and those outside of the area but within the Zone or LDA, as required.

(c) A Capacity Market Seller that intends to offer or certify Energy Efficiency Resources must identify and itemize all Energy Efficiency Resources to be offered as part of its Energy Efficiency measurement and verification plan and certified post-installation measurement and verification report. The Office of Interconnection will provide a list to the relevant electric distribution company for the specific area(s) to review for compliance with the Relevant Electric Retail Regulatory Authority of Capacity Market Sellers that are:

(i) offering Energy Efficiency Resources in an RPM Auction within two (2) Business Days after the deadline for submitting an energy efficiency measurement and verification plan for such RPM Auction; and

(ii) certifying Energy Efficiency Resources with a Delivery Year post-installation measurement and verification report, within two (2) Business Days of receipt of such Delivery Year post-installation measurement and verification report.The relevant electric distribution company for the specific area(s) shall review for compliance with rules from a Relevant Electric Retail Regulatory Authority authorized by FERC to qualify or prohibit Energy Efficiency Resource.

(d) The relevant electric distribution company for the specific area(s) shall review for compliance with rules from a Relevant Electric Retail Regulatory Authority authorized by FERC to qualify or prohibit Energy Efficiency Resource participation and provide a response to the Office of the Interconnection within five (5) Business Days after receiving the list of Capacity Market Sellers offering Energy Efficiency Resources. The Office of the Interconnection will not allow a Capacity Market Seller to offer or certify Energy Efficiency Resources if an electric distribution company denies such Capacity Market Seller to deliver Energy Efficiency Resources in compliance with rules of a Relevant Electric Retail Regulatory Authority authorized by FERC to qualify or prohibit Energy Efficiency Resource participation.

(9) For Incremental Auctions that will be conducted for the 2019/2020 and 2020/2021 Delivery Years, and for RPM Auctions for the 2021/2022 Delivery Year and subsequent Delivery Years, a Capacity Market Seller of Energy Efficiency Resources that cannot satisfy its RPM obligations in any Delivery Year due to the prohibition of participation by a Relevant Electric Retail Regulatory Authority authorized by FERC to prohibit participation of such resources may be

relieved of its Capacity Resource Deficiency Charge by notifying the Office of the Interconnection by no later than seven (7) calendar days prior to the posting of the planning parameters for the Third Incremental Auction of that Delivery Year. After providing such notice, the affected Capacity Market Seller may elect to be relieved of its RPM commitment, and shall not be required to obtain replacement capacity for the resource, and no charges shall be assessed by the Office of the Interconnection for the Capacity Market Seller's deficiency in satisfying its RPM obligation for the resource for such Delivery Year. In such case, however, the Capacity Market Seller shall not be entitled to, nor be paid, any RPM revenues for such resource for that Delivery Year. The Office of the Interconnection will apply corresponding adjustments to the quantity of Buy Bids or Sell Offers in the Incremental Auctions for such Delivery Years in accordance with Tariff, Attachment DD, sections 5.12(b)(ii) and 5.12(b)(iii).

Attachment C

Revisions to the
PJM Open Access Transmission Tariff
and
PJM Reliability Assurance Agreement

(Clean Format)

Sections of the
PJM Open Access Transmission Tariff

(Clean Format)

Definitions – C-D

Canadian Guaranty:

"Canadian Guaranty" shall mean a Corporate Guaranty provided by an Affiliate of a Participant that is domiciled in Canada, and meets all of the provisions of Tariff, Attachment Q.

Cancellation Costs:

"Cancellation Costs" shall mean costs and liabilities incurred in connection with: (a) cancellation of supplier and contractor written orders and agreements entered into to design, construct and install Attachment Facilities, Direct Assignment Facilities and/or Customer-Funded Upgrades, and/or (b) completion of some or all of the required Attachment Facilities, Direct Assignment Facilities and/or Customer-Funded Upgrades, or specific unfinished portions and/or removal of any or all of such facilities which have been installed, to the extent required for the Transmission Provider and/or Transmission Owner(s) to perform their respective obligations under Tariff, Part IV and/or Tariff, Part VI.

Capacity:

"Capacity" shall mean the installed capacity requirement of the Reliability Assurance Agreement or similar such requirements as may be established.

Capacity Emergency Transfer Limit:

"Capacity Emergency Transfer Limit" or "CETL" shall have the meaning provided in the Reliability Assurance Agreement.

Capacity Emergency Transfer Objective:

"Capacity Emergency Transfer Objective" or "CETO" shall have the meaning provided in the Reliability Assurance Agreement.

Capacity Export Transmission Customer:

"Capacity Export Transmission Customer" shall mean a customer taking point to point transmission service under Tariff, Part II to export capacity from a generation resource located in the PJM Region that has qualified for an exception to the RPM must-offer requirement as described in Tariff, Attachment DD, section 6.6(g).

Capacity Import Limit:

"Capacity Import Limit" shall have the meaning provided in the Reliability Assurance Agreement.

Capacity Interconnection Rights:

“Capacity Interconnection Rights” shall mean the rights to input generation as a Generation Capacity Resource into the Transmission System at the Point of Interconnection where the generating facilities connect to the Transmission System.

Capacity Market Buyer:

“Capacity Market Buyer” shall mean a Member that submits bids to buy Capacity Resources in any Incremental Auction.

Capacity Market Seller:

“Capacity Market Seller” shall mean a Member that owns, or has the contractual authority to control the output or load reduction capability of, a Capacity Resource, that has not transferred such authority to another entity, and that offers such resource in the Base Residual Auction or an Incremental Auction.

Capacity Performance Resource:

“Capacity Performance Resource” shall mean a Capacity Resource as described in Tariff, Attachment DD, section 5.5A(a).

Capacity Performance Transition Incremental Auction:

“Capacity Performance Transition Incremental Auction” shall have the meaning specified in Tariff, Attachment DD, section 5.14D.

Capacity Resource:

“Capacity Resource” shall have the meaning provided in the Reliability Assurance Agreement.

Capacity Resource with State Subsidy:

“Capacity Resource with State Subsidy” shall mean (1) a Capacity Resource that is offered into an RPM Auction or otherwise assumes an RPM commitment for which the Capacity Market Seller receives or is entitled to receive one or more State Subsidies for the applicable Delivery Year; (2) a Capacity Resource that has not cleared an RPM Auction for the Delivery Year for which the Capacity Market Seller last received a State Subsidy (or any subsequent Delivery Year) shall still be considered a Capacity Resource with State Subsidy upon the expiration of such State Subsidy until the resource clears an RPM Auction; (3) a Capacity Resource that is the subject of a bilateral transaction (including but not limited to those reported pursuant to Tariff, Attachment DD, section 4.6) shall be deemed a Capacity Resource with State Subsidy to the extent an owner of the facility supporting the Capacity Resource is entitled to a State Subsidy associated with such facility even if the Capacity Market Seller is not entitled to a State Subsidy; and (4) any Jointly Owned Cross-Subsidized Capacity Resource.

Capacity Resource Clearing Price:

"Capacity Resource Clearing Price" shall mean the price calculated for a Capacity Resource that offered and cleared in a Base Residual Auction or Incremental Auction, in accordance with Tariff, Attachment DD, section 5.

Capacity Storage Resource:

"Capacity Storage Resource" shall mean any Energy Storage Resource that participates in the Reliability Pricing Model or is otherwise treated as capacity in PJM's markets such as through a Fixed Resource Requirement Capacity Plan.

Capacity Transfer Right:

"Capacity Transfer Right" shall mean a right, allocated to LSEs serving load in a Locational Deliverability Area, to receive payments, based on the transmission import capability into such Locational Deliverability Area, that offset, in whole or in part, the charges attributable to the Locational Price Adder, if any, included in the Zonal Capacity Price calculated for a Locational Delivery Area.

Capacity Transmission Injection Rights:

"Capacity Transmission Injection Rights" shall mean the rights to schedule energy and capacity deliveries at a Point of Interconnection of a Merchant Transmission Facility with the Transmission System. Capacity Transmission Injection Rights may be awarded only to a Merchant D.C. Transmission Facility and/or Controllable A.C. Merchant Transmission Facilities that connects the Transmission System to another control area. Deliveries scheduled using Capacity Transmission Injection Rights have rights similar to those under Firm Point-to-Point Transmission Service or, if coupled with a generating unit external to the PJM Region that satisfies all applicable criteria specified in the PJM Manuals, similar to Capacity Interconnection Rights.

Charge Economic Maximum Megawatts:

"Charge Economic Maximum Megawatts" shall mean the greatest magnitude of megawatt power consumption available for charging in economic dispatch by an Energy Storage Resource Model Participant in Continuous Mode or in Charge Mode. Charge Economic Maximum Megawatts shall be the Economic Minimum for an Energy Storage Resource in Charge Mode or in Continuous Mode.

Charge Economic Minimum Megawatts:

"Charge Economic Minimum Megawatts" shall mean the smallest magnitude of megawatt power consumption available for charging in economic dispatch by an Energy Storage Resource Model Participant in Charge Mode. Charge Economic Minimum Megawatts shall be the Economic Maximum for an Energy Storage Resource in Charge Mode.

Charge Mode:

"Charge Mode" shall mean the mode of operation of an Energy Storage Resource Model Participant that only includes negative megawatt quantities (i.e., the Energy Storage Resource Model Participant is only withdrawing megawatts from the grid).

Charge Ramp Rate:

"Charge Ramp Rate" shall mean the Ramping Capability of an Energy Storage Resource Model Participant in Charge Mode.

Cleared Capacity Resource with State Subsidy:

"Cleared Capacity Resource with State Subsidy" shall mean a Capacity Resource with State Subsidy that has cleared in an RPM Auction for a Prior Delivery Year pursuant to its Sell Offer at or above its resource-specific MOPR Floor Offer Price or the applicable default New Entry MOPR Floor Offer Price. Notwithstanding the foregoing, any Capacity Resource that previously cleared an RPM Auction before it received or became entitled to receive a State Subsidy shall also be deemed a Cleared Capacity Resource with State Subsidy.

Cold/Warm/Hot Notification Time:

"Cold/Warm/Hot Notification Time" shall mean the time interval between PJM notification and the beginning of the start sequence for a generating unit that is currently in its cold/warm/hot temperature state. The start sequence may include steps such as any valve operation, starting feed water pumps, startup of auxiliary equipment, etc.

Cold/Warm/Hot Start-up Time:

For all generating units that are not combined cycle units, "Cold/Warm/Hot Start-up Time" shall mean the time interval, measured in hours, from the beginning of the start sequence to the point after generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero for a generating unit in its cold/warm/hot temperature state. For combined cycle units, "Cold/Warm/Hot Start-up Time" shall mean the time interval from the beginning of the start sequence to the point after first combustion turbine generator breaker closure in its cold/warm/hot temperature state, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero. For all generating units, the start sequence may include steps such as any valve operation, starting feed water pumps, startup of auxiliary equipment, etc. Other more detailed actions that could signal the beginning of the start sequence could include, but are not limited to, the operation of pumps, condensers, fans, water chemistry evaluations, checklists, valves, fuel systems, combustion turbines, starting engines or systems, maintaining stable fuel/air ratios, and other auxiliary equipment necessary for startup.

Cold Weather Alert:

"Cold Weather Alert" shall mean the notice that PJM provides to PJM Members, Transmission Owners, resource owners and operators, customers, and regulators to prepare personnel and facilities for expected extreme cold weather conditions.

Collateral:

"Collateral" shall be a cash deposit, including any interest, or letter of credit in an amount and form determined by and acceptable to PJMSettlement, provided by a Participant to PJMSettlement as security in order to participate in the PJM Markets or take Transmission Service.

Collateral Call:

"Collateral Call" shall mean a notice to a Participant that additional Collateral, or possibly early payment, is required in order to remain in, or to regain, compliance with Tariff, Attachment Q.

Commencement Date:

"Commencement Date" shall mean the date on which Interconnection Service commences in accordance with an Interconnection Service Agreement.

Committed Offer:

The "Committed Offer" shall mean 1) for pool-scheduled resources, an offer on which a resource was scheduled by the Office of the Interconnection for a particular clock hour for an Operating Day, and 2) for self-scheduled resources, either the offer on which the Market Seller has elected to schedule the resource or the applicable offer for the resource determined pursuant to Operating Agreement, Schedule 1, section 6.4, or Operating Agreement, Schedule 1, section 6.6 for a particular clock hour for an Operating Day.

Completed Application:

"Completed Application" shall mean an application that satisfies all of the information and other requirements of the Tariff, including any required deposit.

Compliance Aggregation Area (CAA):

"Compliance Aggregation Area" or "CAA" shall mean a geographic area of Zones or sub-Zones that are electrically-contiguous and experience for the relevant Delivery Year, based on Resource Clearing Prices of, for Delivery Years through May 31, 2018, Annual Resources and for the 2018/2019 Delivery Year and subsequent Delivery Years, Capacity Performance Resources, the same locational price separation in the Base Residual Auction, the same locational price separation in the First Incremental Auction, the same locational price separation in the Second Incremental Auction, the same locational price separation in the Third Incremental Auction.

Conditional Incremental Auction:

"Conditional Incremental Auction" shall mean an Incremental Auction conducted for a Delivery Year if and when necessary to secure commitments of additional capacity to address reliability criteria violations arising from the delay in a Backbone Transmission upgrade that was modeled in the Base Residual Auction for such Delivery Year.

CONE Area:

"CONE Area" shall mean the areas listed in Tariff, Attachment DD, section 5.10(a)(iv)(A) and any LDAs established as CONE Areas pursuant to Tariff, Attachment DD, section 5.10(a)(iv)(B).

Confidential Information:

"Confidential Information" shall mean any confidential, proprietary, or trade secret information of a plan, specification, pattern, procedure, design, device, list, concept, policy, or compilation relating to the present or planned business of a New Service Customer, Transmission Owner, or other Interconnection Party or Construction Party, which is designated as confidential by the party supplying the information, whether conveyed verbally, electronically, in writing, through inspection, or otherwise, and shall include, without limitation, all information relating to the producing party's technology, research and development, business affairs and pricing, and any information supplied by any New Service Customer, Transmission Owner, or other Interconnection Party or Construction Party to another such party prior to the execution of an Interconnection Service Agreement or a Construction Service Agreement.

Congestion Price:

"Congestion Price" shall mean the congestion component of the Locational Marginal Price, which is the effect on transmission congestion costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource, based on the effect of increased generation from or consumption by the resource on transmission line loadings, calculated as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

Consolidated Transmission Owners Agreement, PJM Transmission Owners Agreement or Transmission Owners Agreement:

"Consolidated Transmission Owners Agreement," "PJM Transmission Owners Agreement" or "Transmission Owners Agreement" shall mean the certain Consolidated Transmission Owners Agreement dated as of December 15, 2005, by and among the Transmission Owners and by and between the Transmission Owners and PJM Interconnection, L.L.C. on file with the Commission, as amended from time to time.

Constraint Relaxation Logic:

“Constraint Relaxation Logic” shall mean the logic applied in the market clearing software where the transmission limit is increased to prevent the Transmission Constraint Penalty Factor from setting the Marginal Value of a transmission constraint.

Constructing Entity:

“Constructing Entity” shall mean either the Transmission Owner or the New Services Customer, depending on which entity has the construction responsibility pursuant to Tariff, Part VI and the applicable Construction Service Agreement; this term shall also be used to refer to an Interconnection Customer with respect to the construction of the Customer Interconnection Facilities.

Construction Party:

“Construction Party” shall mean a party to a Construction Service Agreement. “Construction Parties” shall mean all of the Parties to a Construction Service Agreement.

Construction Service Agreement:

“Construction Service Agreement” shall mean either an Interconnection Construction Service Agreement or an Upgrade Construction Service Agreement.

Contingent Facilities:

“Contingent Facilities” shall mean those unbuilt Interconnection Facilities and Network Upgrades upon which the Interconnection Request’s costs, timing, and study findings are dependent and, if delayed or not built, could cause a need for restudies of the Interconnection Request or a reassessment of the Interconnection Facilities and/or Network Upgrades and/or costs and timing.

Continuous Mode:

“Continuous Mode” shall mean the mode of operation of an Energy Storage Resource Model Participant that includes both negative and positive megawatt quantities (i.e., the Energy Storage Resource Model Participant is capable of continually and immediately transitioning from withdrawing megawatt quantities from the grid to injecting megawatt quantities onto the grid or injecting megawatts to withdrawing megawatts). Energy Storage Resource Model Participants operating in Continuous Mode are considered to have an unlimited ramp rate. Continuous Mode requires Discharge Economic Maximum Megawatts to be zero or correspond to an injection, and Charge Economic Maximum Megawatts to be zero or correspond to a withdrawal.

Control Area:

“Control Area” shall mean an electric power system or combination of electric power systems bounded by interconnection metering and telemetry to which a common automatic generation control scheme is applied in order to:

(1) match the power output of the generators within the electric power system(s) and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);

(2) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;

(3) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and

(4) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

Control Zone:

“Control Zone” shall have the meaning given in the Operating Agreement.

Controllable A.C. Merchant Transmission Facilities:

“Controllable A.C. Merchant Transmission Facilities” shall mean transmission facilities that (1) employ technology which Transmission Provider reviews and verifies will permit control of the amount and/or direction of power flow on such facilities to such extent as to effectively enable the controllable facilities to be operated as if they were direct current transmission facilities, and (2) that are interconnected with the Transmission System pursuant to Tariff, Part IV and Tariff, Part VI.

Coordinated External Transaction:

“Coordinated External Transaction” shall mean a transaction to simultaneously purchase and sell energy on either side of a CTS Enabled Interface in accordance with the procedures of Operating Agreement, Schedule 1, section 1.13, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.13.

Coordinated Transaction Scheduling:

“Coordinated Transaction Scheduling” or “CTS” shall mean the scheduling of Coordinated External Transactions at a CTS Enabled Interface in accordance with the procedures of Operating Agreement, Schedule 1, section 1.13, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.13.

Corporate Guaranty:

“Corporate Guaranty” shall mean a legal document used by an entity to guaranty the obligations of another entity.

Cost of New Entry:

“Cost of New Entry” or “CONE” shall mean the nominal levelized cost of a Reference Resource, as determined in accordance with Tariff, Attachment DD, section 5.

Costs:

As used in Tariff, Part IV, Tariff, Part VI and related attachments, “Costs” shall mean costs and expenses, as estimated or calculated, as applicable, including, but not limited to, capital expenditures, if applicable, and overhead, return, and the costs of financing and taxes and any Incidental Expenses.

Counterparty:

“Counterparty” shall mean PJMSettlement as the contracting party, in its name and own right and not as an agent, to an agreement or transaction with a Market Participant or other entities, including the agreements and transactions with customers regarding transmission service and other transactions under the PJM Tariff and the Operating Agreement. PJMSettlement shall not be a counterparty to (i) any bilateral transactions between Members, or (ii) any Member’s self-supply of energy to serve its load, or (iii) any Member’s self-schedule of energy reported to the Office of the Interconnection to the extent that energy serves that Member’s own load .

Credit Available for Export Transactions:

“Credit Available for Export Transactions” shall mean a designation of credit to be used for Export Transactions that is allocated by each Market Participant from its Credit Available for Virtual Transactions, and which reduces the Market Participant's Credit Available for Virtual Transactions accordingly.

Credit Available for Virtual Transactions:

“Credit Available for Virtual Transactions” shall mean the Market Participant’s Working Credit Limit for Virtual Transactions calculated on its credit provided in compliance with its Peak Market Activity requirement plus available credit submitted above that amount, less any unpaid billed and unbilled amounts owed to PJMSettlement, plus any unpaid unbilled amounts owed by PJMSettlement to the Market Participant, less any applicable credit required for Minimum Participation Requirements, FTRs, RPM activity, or other credit requirement determinants as defined in Tariff, Attachment Q.

Credit Breach:

“Credit Breach” shall mean the status of a Participant that does not currently meet the requirements of Tariff, Attachment Q or other provisions of the Agreements.

Credit-Limited Offer:

"Credit-Limited Offer" shall mean a Sell Offer that is submitted by a Market Participant in an RPM Auction subject to a maximum credit requirement specified by such Market Participant.

Credit Score:

"Credit Score" shall mean a composite numerical score scaled from 0-100 as calculated by PJMSettlement that incorporates various predictors of creditworthiness.

CTS Enabled Interface:

"CTS Enabled Interface" shall mean an interface between the PJM Control Area and an adjacent Control Area at which the Office of the Interconnection has authorized the use of Coordinated Transaction Scheduling ("CTS"). The CTS Enabled Interfaces between the PJM Control Area and the New York Independent System Operator, Inc. Control Area shall be designated in the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C., Schedule A (PJM Rate Schedule FERC No. 45). The CTS Enabled Interfaces between the PJM Control Area and the Midcontinent Independent System Operator, Inc. shall be designated consistent with Attachment 3, section 2 of the Joint Operating Agreement between Midcontinent Independent System Operator, Inc. and PJM Interconnection, L.L.C.

CTS Interface Bid:

"CTS Interface Bid" shall mean a unified real-time bid to simultaneously purchase and sell energy on either side of a CTS Enabled Interface in accordance with the procedures of Operating Agreement, Schedule 1, section 1.13, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.13.

Curtailment:

"Curtailment" shall mean a reduction in firm or non-firm transmission service in response to a transfer capability shortage as a result of system reliability conditions.

Curtailment Service Provider:

"Curtailment Service Provider" or "CSP" shall mean a Member or a Special Member, which action on behalf of itself or one or more other Members or non-Members, participates in the PJM Interchange Energy Market, Ancillary Services markets, and/or Reliability Pricing Model by causing a reduction in demand.

Customer Facility:

“Customer Facility” shall mean Generation Facilities or Merchant Transmission Facilities interconnected with or added to the Transmission System pursuant to an Interconnection Request under Tariff, Part IV.

Customer-Funded Upgrade:

“Customer-Funded Upgrade” shall mean any Network Upgrade, Local Upgrade, or Merchant Network Upgrade for which cost responsibility (i) is imposed on an Interconnection Customer or an Eligible Customer pursuant to Tariff, Part VI, section 217, or (ii) is voluntarily undertaken by a New Service Customer in fulfillment of an Upgrade Request. No Network Upgrade, Local Upgrade or Merchant Network Upgrade or other transmission expansion or enhancement shall be a Customer-Funded Upgrade if and to the extent that the costs thereof are included in the rate base of a public utility on which a regulated return is earned.

Customer Interconnection Facilities:

“Customer Interconnection Facilities” shall mean all facilities and equipment owned and/or controlled, operated and maintained by Interconnection Customer on Interconnection Customer’s side of the Point of Interconnection identified in the appropriate appendices to the Interconnection Service Agreement and to the Interconnection Construction Service Agreement, including any modifications, additions, or upgrades made to such facilities and equipment, that are necessary to physically and electrically interconnect the Customer Facility with the Transmission System.

Daily Deficiency Rate:

“Daily Deficiency Rate” shall mean the rate employed to assess certain deficiency charges under Tariff, Attachment DD, section 7, Tariff, Attachment DD, section 8, Tariff, Attachment DD, section 9, or Tariff, Attachment DD, section 13.

Daily Unforced Capacity Obligation:

“Daily Unforced Capacity Obligation” shall mean the capacity obligation of a Load Serving Entity during the Delivery Year, determined in accordance with Reliability Assurance Agreement, Schedule 8, or, as to an FRR entity, in Reliability Assurance Agreement, Schedule 8.1.

Day-ahead Congestion Price:

“Day-ahead Congestion Price” shall mean the Congestion Price resulting from the Day-ahead Energy Market.

Day-ahead Energy Market:

“Day-ahead Energy Market” shall mean the schedule of commitments for the purchase or sale of energy and payment of Transmission Congestion Charges developed by the Office of the

Interconnection as a result of the offers and specifications submitted in accordance with Operating Agreement, Schedule 1, section 1.10 and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.

Day-ahead Energy Market Injection Congestion Credits:

“Day-ahead Energy Market Injection Congestion Credits” shall mean those congestion credits paid to Market Participants for supply transactions in the Day-ahead Energy Market including generation schedules, Increment Offers, Up-to Congestion Transactions, import transactions, and Day-Ahead Pseudo-Tie Transactions.

Day-ahead Energy Market Transmission Congestion Charges:

“Day-ahead Energy Market Transmission Congestion Charges” shall be equal to the sum of Day-ahead Energy Market Withdrawal Congestion Charges minus [the sum of Day-ahead Energy Market Injection Congestion Credits plus any congestion charges calculated pursuant to the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38), plus any congestion charges calculated pursuant to the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 45), plus any congestion charges calculated pursuant to agreements between the Office of the Interconnection and other entities, as applicable)].

Day-ahead Energy Market Withdrawal Congestion Charges:

“Day-ahead Energy Market Withdrawal Congestion Charges” shall mean those congestion charges collected from Market Participants for withdrawal transactions in the Day-ahead Energy Market from transactions including Demand Bids, Decrement Bids, Up-to Congestion Transactions, Export Transactions, and Day-Ahead Pseudo-Tie Transactions.

Day-ahead Loss Price:

“Day-ahead Loss Price” shall mean the Loss Price resulting from the Day-ahead Energy Market.

Day-ahead Prices:

“Day-ahead Prices” shall mean the Locational Marginal Prices resulting from the Day-ahead Energy Market.

Day-Ahead Pseudo-Tie Transaction:

“Day-Ahead Pseudo-Tie Transaction” shall mean a transaction scheduled in the Day-ahead Energy Market to the PJM-MISO interface from a generator within the PJM balancing authority area that Pseudo-Ties into the MISO balancing authority area.

Day-ahead Scheduling Reserves:

"Day-ahead Scheduling Reserves" shall mean thirty-minute reserves as defined by the Reliability*First* Corporation and SERC.

Day-ahead Scheduling Reserves Market:

"Day-ahead Scheduling Reserves Market" shall mean the schedule of commitments for the purchase or sale of Day-ahead Scheduling Reserves developed by the Office of the Interconnection as a result of the offers and specifications submitted in accordance with Operating Agreement, Schedule 1, section 1.10 and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.

Day-ahead Scheduling Reserves Requirement:

"Day-ahead Scheduling Reserves Requirement" shall mean the sum of Base Day-ahead Scheduling Reserves Requirement and Additional Day-ahead Scheduling Reserves Requirement.

Day-ahead Scheduling Reserves Resources:

"Day-ahead Scheduling Reserves Resources" shall mean synchronized and non-synchronized generation resources and Demand Resources electrically located within the PJM Region that are capable of providing Day-ahead Scheduling Reserves.

Day-ahead Settlement Interval:

"Day-ahead Settlement Interval" shall mean the interval used by settlements, which shall be every one clock hour.

Day-ahead System Energy Price:

"Day-ahead System Energy Price" shall mean the System Energy Price resulting from the Day-ahead Energy Market.

Deactivation:

"Deactivation" shall mean the retirement or mothballing of a generating unit governed by Tariff, Part V.

Deactivation Avoidable Cost Credit:

"Deactivation Avoidable Cost Credit" shall mean the credit paid to Generation Owners pursuant to Tariff, Part V, section 114.

Deactivation Avoidable Cost Rate:

“Deactivation Avoidable Cost Rate” shall mean the formula rate established pursuant to Tariff, Part V, section 115 .

Deactivation Date:

“Deactivation Date” shall mean the date a generating unit within the PJM Region is either retired or mothballed and ceases to operate.

Decrement Bid:

“Decrement Bid” shall mean a type of Virtual Transaction that is a bid to purchase energy at a specified location in the Day-ahead Energy Market. A cleared Decrement Bid results in scheduled load at the specified location in the Day-ahead Energy Market.

Default:

As used in the Interconnection Service Agreement and Construction Service Agreement, “Default” shall mean the failure of a Breaching Party to cure its Breach in accordance with the applicable provisions of an Interconnection Service Agreement or Construction Service Agreement.

Delivering Party:

“Delivering Party” shall mean the entity supplying capacity and energy to be transmitted at Point(s) of Receipt.

Delivery Year:

“Delivery Year” shall mean the Planning Period for which a Capacity Resource is committed pursuant to the auction procedures specified in Tariff, Attachment DD, or pursuant to an FRR Capacity Plan under Reliability Assurance Agreement, Schedule 8.1.

Demand Bid:

“Demand Bid” shall mean a bid, submitted by a Load Serving Entity in the Day-ahead Energy Market, to purchase energy at its contracted load location, for a specified timeframe and megawatt quantity, that if cleared will result in energy being scheduled at the specified location in the Day-ahead Energy Market and in the physical transfer of energy during the relevant Operating Day.

Demand Bid Limit:

“Demand Bid Limit” shall mean the largest MW volume of Demand Bids that may be submitted by a Load Serving Entity for any hour of an Operating Day, as determined pursuant to Operating Agreement, Schedule 1, section 1.10.1B, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.1B.

Demand Bid Screening:

"Demand Bid Screening" shall mean the process by which Demand Bids are reviewed against the applicable Demand Bid Limit, and rejected if they would exceed that limit, as determined pursuant to Operating Agreement, Schedule 1, section 1.10.1B, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.1B.

Demand Resource:

"Demand Resource" shall mean a resource with the capability to provide a reduction in demand.

Demand Resource Factor or DR Factor:

"Demand Resource Factor" or ("DR Factor") shall have the meaning specified in the Reliability Assurance Agreement.

Designated Agent:

"Designated Agent" shall mean any entity that performs actions or functions on behalf of the Transmission Provider, a Transmission Owner, an Eligible Customer, or the Transmission Customer required under the Tariff.

Designated Entity:

"Designated Entity" shall have the same meaning provided in the Operating Agreement.

Direct Assignment Facilities:

"Direct Assignment Facilities" shall mean facilities or portions of facilities that are constructed for the sole use/benefit of a particular Transmission Customer requesting service under the Tariff. Direct Assignment Facilities shall be specified in the Service Agreement that governs service to the Transmission Customer and shall be subject to Commission approval.

Direct Charging Energy:

"Direct Charging Energy" shall mean the energy that an Energy Storage Resource purchases from the PJM Interchange Energy Market and (i) later resells to the PJM Interchange Energy Market; or (ii) is lost to conversion inefficiencies, provided that such inefficiencies are an unavoidable component of the conversion, storage, and discharge process that is used to resell energy back to the PJM Interchange Energy Market.

Direct Load Control:

"Direct Load Control" shall mean load reduction that is controlled directly by the Curtailment Service Provider's market operations center or its agent, in response to PJM instructions.

Discharge Economic Maximum Megawatts:

"Discharge Economic Maximum Megawatts" shall mean the maximum megawatt power output available for discharge in economic dispatch by an Energy Storage Resource Model Participant in Continuous Mode or in Discharge Mode. Discharge Economic Maximum Megawatts shall be the Economic Maximum for an Energy Storage Resource in Discharge Mode or in Continuous Mode.

Discharge Economic Minimum Megawatts:

"Discharge Economic Minimum Megawatts" shall mean the minimum megawatt power output available for discharge in economic dispatch by an Energy Storage Resource Model Participant in Discharge Mode. Discharge Economic Minimum Megawatts shall be the Economic Minimum for an Energy Storage Resource in Discharge Mode.

Discharge Mode:

"Discharge Mode" shall mean the mode of operation of an Energy Storage Resource Model Participant that only includes positive megawatt quantities (i.e., the Energy Storage Resource Model Participant is only injecting megawatts onto the grid).

***Discharge Ramp Rate**:*

"Discharge Ramp Rate" shall mean the Ramping Capability of an Energy Storage Resource Model Participant in Discharge Mode.

Dispatch Rate:

"Dispatch Rate" shall mean the control signal, expressed in dollars per megawatt-hour, calculated and transmitted continuously and dynamically to direct the output level of all generation resources dispatched by the Office of the Interconnection in accordance with the Offer Data.

Dispatched Charging Energy:

"Dispatched Charging Energy" shall mean Direct Charging Energy that an Energy Storage Resource Model Participant receives from the electric grid pursuant to PJM dispatch while providing *one of the following* services in the PJM markets*: Energy Imbalance Service pursuant to Tariff, Schedule 4; Regulation; Tier 2 Synchronized Reserves; or Reactive Service. Energy Storage Resource Model Participants shall be considered to be providing Energy Imbalance Service when they are dispatchable by PJM in real-time.*

Dynamic Schedule:

"Dynamic Schedule" shall have the same meaning provided in the Operating Agreement.

Dynamic Transfer:

"Dynamic Transfer" shall have the same meaning provided in the Operating Agreement.

Definitions – I – J - K

IDR Transfer Agreement:

"IDR Transfer Agreement" shall mean an agreement to transfer, subject to the terms of Tariff, Part VI, section 237, Incremental Deliverability Rights to a party for the purpose of eliminating or reducing the need for Local or Network Upgrades that would otherwise have been the responsibility of the party receiving such rights.

Immediate-need Reliability Project:

"Immediate-need Reliability Project" shall have the same meaning provided in the Operating Agreement.

Inadvertent Interchange:

"Inadvertent Interchange" shall mean the difference between net actual energy flow and net scheduled energy flow into or out of the individual Control Areas operated by PJM.

Incidental Expenses:

"Incidental Expenses" shall mean those expenses incidental to the performance of construction pursuant to an Interconnection Construction Service Agreement, including, but not limited to, the expense of temporary construction power, telecommunications charges, Interconnected Transmission Owner expenses associated with, but not limited to, document preparation, design review, installation, monitoring, and construction-related operations and maintenance for the Customer Facility and for the Interconnection Facilities.

Incremental Auction:

"Incremental Auction" shall mean any of several auctions conducted for a Delivery Year after the Base Residual Auction for such Delivery Year and before the first day of such Delivery Year, including the First Incremental Auction, Second Incremental Auction, Third Incremental Auction or Conditional Incremental Auction. Incremental Auctions (other than the Conditional Incremental Auction shall be held for the purposes of:

(i) allowing Market Sellers that committed Capacity Resources in the Base Residual Auction for a Delivery Year, which subsequently are determined to be unavailable to deliver the committed Unforced Capacity in such Delivery Year (due to resource retirement, resource cancellation or construction delay, resource derating, EFORd increase, a decrease in the Nominated Demand Resource Value of a Planned Demand Resource, delay or cancellation of a Qualifying Transmission Upgrade, or similar occurrences) to submit Buy Bids for replacement Capacity Resources; and

(ii) allowing the Office of the Interconnection to reduce or increase the amount of committed capacity secured in prior auctions for such Delivery Year if, as a result of changed circumstances or expectations since the prior auction(s), there is, respectively, a significant excess or significant deficit of committed capacity for such Delivery Year, for the PJM Region or for an LDA.

Incremental Auction Revenue Rights:

“Incremental Auction Revenue Rights” shall mean the additional Auction Revenue Rights, not previously feasible, created by the addition of Incremental Rights-Eligible Required Transmission Enhancements, Merchant Transmission Facilities, or of one or more Customer-Funded Upgrades.

Incremental Available Transfer Capability Revenue Rights:

“Incremental Available Transfer Capability Revenue Rights” shall mean the rights to revenues that are derived from incremental Available Transfer Capability created by the addition of Merchant Transmission Facilities or of one of more Customer-Funded Upgrades.

Incremental Capacity Transfer Right:

“Incremental Capacity Transfer Right” shall mean a Capacity Transfer Right allocated to a Generation Interconnection Customer or Transmission Interconnection Customer obligated to fund a transmission facility or upgrade, to the extent such upgrade or facility increases the transmission import capability into a Locational Deliverability Area, or a Capacity Transfer Right allocated to a Responsible Customer in accordance with Tariff, Schedule 12A.

Incremental Deliverability Rights (IDRs):

“Incremental Deliverability Rights” or “IDRs” shall mean the rights to the incremental ability, resulting from the addition of Merchant Transmission Facilities, to inject energy and capacity at a point on the Transmission System, such that the injection satisfies the deliverability requirements of a Capacity Resource. Incremental Deliverability Rights may be obtained by a generator or a Generation Interconnection Customer, pursuant to an IDR Transfer Agreement, to satisfy, in part, the deliverability requirements necessary to obtain Capacity Interconnection Rights.

Incremental Energy Offer:

“Incremental Energy Offer” shall mean offer segments comprised of a pairing of price (in dollars per MWh) and megawatt quantities, which must be a non-decreasing function and taken together produce all of the energy segments above a resource’s Economic Minimum. No-load Costs are not included in the Incremental Energy Offer.

Incremental Multi-Driver Project:

“Incremental Multi-Driver Project” shall have the same meaning provided in the Operating Agreement.

Incremental Rights-Eligible Required Transmission Enhancements:

"Incremental Rights-Eligible Required Transmission Enhancements" shall mean Regional Facilities and Necessary Lower Voltage Facilities or Lower Voltage Facilities (as defined in Tariff, Schedule 12) and meet one of the following criteria: (1) cost responsibility is assigned to non-contiguous Zones that are not directly electrically connected; or (2) cost responsibility is assigned to Merchant Transmission Providers that are Responsible Customers.

Increment Offer:

"Increment Offer" shall mean a type of Virtual Transaction that is an offer to sell energy at a specified location in the Day-ahead Energy Market. A cleared Increment Offer results in scheduled generation at the specified location in the Day-ahead Energy Market.

Initial Operation:

"Initial Operation" shall mean the commencement of operation of the Customer Facility and Customer Interconnection Facilities after satisfaction of the conditions of Tariff, Attachment O-Appendix 2, section 1.4 (an Interconnection Service Agreement).

Interconnected Entity:

"Interconnected Entity" shall mean either the Interconnection Customer or the Interconnected Transmission Owner; Interconnected Entities shall mean both of them.

Interconnected Transmission Owner:

"Interconnected Transmission Owner" shall mean the Transmission Owner to whose transmission facilities or distribution facilities Customer Interconnection Facilities are, or as the case may be, a Customer Facility is, being directly connected. When used in an Interconnection Construction Service Agreement, the term may refer to a Transmission Owner whose facilities must be upgraded pursuant to the Facilities Study, but whose facilities are not directly interconnected with those of the Interconnection Customer.

Interconnection Construction Service Agreement:

"Interconnection Construction Service Agreement" shall mean the agreement entered into by an Interconnection Customer, Interconnected Transmission Owner and the Transmission Provider pursuant to Tariff, Part VI, Subpart B and in the form set forth in Tariff, Attachment P, relating to construction of Attachment Facilities, Network Upgrades, and/or Local Upgrades and coordination of the construction and interconnection of an associated Customer Facility. A separate Interconnection Construction Service Agreement will be executed with each Transmission Owner that is responsible for construction of any Attachment Facilities, Network Upgrades, or Local Upgrades associated with interconnection of a Customer Facility.

Interconnection Customer:

"Interconnection Customer" shall mean a Generation Interconnection Customer and/or a Transmission Interconnection Customer.

Interconnection Facilities:

"Interconnection Facilities" shall mean the Transmission Owner Interconnection Facilities and the Customer Interconnection Facilities.

Interconnection Feasibility Study:

"Interconnection Feasibility Study" shall mean either a Generation Interconnection Feasibility Study or Transmission Interconnection Feasibility Study.

Interconnection Party:

"Interconnection Party" shall mean a Transmission Provider, Interconnection Customer, or the Interconnected Transmission Owner. Interconnection Parties shall mean all of them.

Interconnection Request:

"Interconnection Request" shall mean a Generation Interconnection Request, a Transmission Interconnection Request and/or an IDR Transfer Agreement.

Interconnection Service:

"Interconnection Service" shall mean the physical and electrical interconnection of the Customer Facility with the Transmission System pursuant to the terms of Tariff, Part IV and Tariff, Part VI and the Interconnection Service Agreement entered into pursuant thereto by Interconnection Customer, the Interconnected Transmission Owner and Transmission Provider.

Interconnection Service Agreement:

"Interconnection Service Agreement" shall mean an agreement among the Transmission Provider, an Interconnection Customer and an Interconnected Transmission Owner regarding interconnection under Tariff, Part IV and Tariff, Part VI.

Interconnection Studies:

"Interconnection Studies" shall mean the Interconnection Feasibility Study, the System Impact Study, and the Facilities Study described in Tariff, Part IV and Tariff, Part VI.

Interface Pricing Point:

"Interface Pricing Point" shall have the meaning specified in Operating Agreement, Schedule 1, section 2.6A, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.6A.

Intermittent Resource:

"Intermittent Resource" shall mean a Generation Capacity Resource with output that can vary as a function of its energy source, such as wind, solar, run of river hydroelectric power and other renewable resources.

Internal Market Buyer:

"Internal Market Buyer" shall mean a Market Buyer making purchases of energy from the PJM Interchange Energy Market for ultimate consumption by end-users inside the PJM Region that are served by Network Transmission Service.

Interregional Transmission Project:

"Interregional Transmission Project" shall mean transmission facilities that would be located within two or more neighboring transmission planning regions and are determined by each of those regions to be a more efficient or cost effective solution to regional transmission needs.

Interruption:

"Interruption" shall mean a reduction in non-firm transmission service due to economic reasons pursuant to Tariff, Part II, section 14.7.

Jointly Owned Cross-Subsidized Capacity Resource:

"Jointly Owned Cross-Subsidized Capacity Resource" shall mean a Capacity Resource that is supported by a facility that is jointly owned, where at least one owner is entitled to or receives a State Subsidy associated with such Capacity Resource, and therefore shall be considered a Capacity Resource with State Subsidy; provided however, in the event that the material rights and obligations of such generating facility are in pari passu, meaning that such rights and obligations are allocated among the owners pro rata based on ownership share, only Capacity Resources of those owners entitled to receive or receiving a State Subsidy shall have their share of such resource considered a Capacity Resource with a State Subsidy and Capacity Resources of owners not entitled to a State Subsidy shall not be considered a Capacity Resource with a State Subsidy. Each of these designations may be overcome by either Capacity Market Seller demonstrating to the Office of Interconnection, with advice and input from the Market Monitoring Unit, that there is no cross-subsidization or the Office of the Interconnection, with review and input from the Market Monitor, finds based on sufficient evidence, that there is cross-subsidization.

Definitions – L – M – N

Limited Demand Resource:

"Limited Demand Resource**"** shall have the meaning specified in the Reliability Assurance Agreement.

Limited Demand Resource Reliability Target:

"Limited Demand Resource Reliability Target**"** for the PJM Region or an LDA, shall mean the maximum amount of Limited Demand Resources determined by PJM to be consistent with the maintenance of reliability, stated in Unforced Capacity that shall be used to calculate the Minimum Extended Summer Demand Resource Requirement for Delivery Years through May 31, 2017 and the Limited Resource Constraint for the 2017/2018 and 2018/2019 Delivery Years for the PJM Region or such LDA. As more fully set forth in the PJM Manuals, PJM calculates the Limited Demand Resource Reliability Target by first: i) testing the effects of the ten-interruption requirement by comparing possible loads on peak days under a range of weather conditions (from the daily load forecast distributions for the Delivery Year in question) against possible generation capacity on such days under a range of conditions (using the cumulative capacity distributions employed in the Installed Reserve Margin study for the PJM Region and in the Capacity Emergency Transfer Objective study for the relevant LDAs for such Delivery Year) and, by varying the assumed amounts of DR that is committed and displaces committed generation, determines the DR penetration level at which there is a ninety percent probability that DR will not be called (based on the applicable operating reserve margin for the PJM Region and for the relevant LDAs) more than ten times over those peak days; ii) testing the six-hour duration requirement by calculating the MW difference between the highest hourly unrestricted peak load and seventh highest hourly unrestricted peak load on certain high peak load days (e.g., the annual peak, loads above the weather normalized peak, or days where load management was called) in recent years, then dividing those loads by the forecast peak for those years and averaging the result; and (iii) (for the 2016/2017 and 2017/2018 Delivery Years) testing the effects of the six-hour duration requirement by comparing possible hourly loads on peak days under a range of weather conditions (from the daily load forecast distributions for the Delivery Year in question) against possible generation capacity on such days under a range of conditions (using a Monte Carlo model of hourly capacity levels that is consistent with the capacity model employed in the Installed Reserve Margin study for the PJM Region and in the Capacity Emergency Transfer Objective study for the relevant LDAs for such Delivery Year) and, by varying the assumed amounts of DR that is committed and displaces committed generation, determines the DR penetration level at which there is a ninety percent probability that DR will not be called (based on the applicable operating reserve margin for the PJM Region and for the relevant LDAs) for more than six hours over any one or more of the tested peak days. Second, PJM adopts the lowest result from these three tests as the Limited Demand Resource Reliability Target. The Limited Demand Resource Reliability Target shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the DR Factor] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

Limited Resource Constraint:

"Limited Resource Constraint" shall mean, for the 2017/2018 Delivery Year and for FRR Capacity Plans the 2017/2018 and Delivery Years, for the PJM Region or each LDA for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for a Delivery Year, a limit on the total amount of Unforced Capacity that can be committed as Limited Demand Resources for the 2017/2018 Delivery Year in the PJM Region or in such LDA, calculated as the Limited Demand Resource Reliability Target for the PJM Region or such LDA, respectively, minus the Short Term Resource Procurement Target for the PJM Region or such LDA, respectively.

Limited Resource Price Decrement:
"Limited Resource Price Decrement" shall mean, for the 2017/2018 Delivery Year, a difference between the clearing price for Limited Demand Resources and the clearing price for Extended Summer Demand Resources and Annual Resources, representing the cost to procure additional Extended Summer Demand Resources or Annual Resources out of merit order when the Limited Resource Constraint is binding.

List of Approved Contractors:

"List of Approved Contractors" shall mean a list developed by each Transmission Owner and published in a PJM Manual of (a) contractors that the Transmission Owner considers to be qualified to install or construct new facilities and/or upgrades or modifications to existing facilities on the Transmission Owner's system, provided that such contractors may include, but need not be limited to, contractors that, in addition to providing construction services, also provide design and/or other construction-related services, and (b) manufacturers or vendors of major transmission-related equipment (e.g., high-voltage transformers, transmission line, circuit breakers) whose products the Transmission Owner considers acceptable for installation and use on its system.

Load Management:

"Load Management" shall mean a Demand Resource ("DR") as defined in the Reliability Assurance Agreement.

Load Management Event:

"Load Management Event" shall mean a) a single temporally contiguous dispatch of Demand Resources in a Compliance Aggregation Area during an Operating Day, or b) multiple dispatches of Demand Resources in a Compliance Aggregation Area during an Operating Day that are temporally contiguous.

Load Ratio Share:

“Load Ratio Share” shall mean the ratio of a Transmission Customer’s Network Load to the Transmission Provider’s total load.

Load Reduction Event:

“Load Reduction Event” shall mean a reduction in demand by a Member or Special Member for the purpose of participating in the PJM Interchange Energy Market.

Load Serving Charging Energy:

“Load Serving Charging Energy” shall mean energy that is purchased from the PJM Interchange Energy Market and stored in an Energy Storage Resource for later resale to end-use load.

Load Serving Entity (LSE):

“Load Serving Entity” or “LSE” shall have the meaning specified in the Reliability Assurance Agreement.

Load Shedding:

“Load Shedding” shall mean the systematic reduction of system demand by temporarily decreasing load in response to transmission system or area capacity shortages, system instability, or voltage control considerations under Tariff, Part II or Part III.

Local Upgrades:

“Local Upgrades” shall mean modifications or additions of facilities to abate any local thermal loading, voltage, short circuit, stability or similar engineering problem caused by the interconnection and delivery of generation to the Transmission System. Local Upgrades shall include:

(i) Direct Connection Local Upgrades which are Local Upgrades that only serve the Customer Interconnection Facility and have no impact or potential impact on the Transmission System until the final tie-in is complete; and

(ii) Non-Direct Connection Local Upgrades which are parallel flow Local Upgrades that are not Direct Connection Local Upgrades.

Location:

“Location” as used in the Economic Load Response rules shall mean an end-use customer site as defined by the relevant electric distribution company account number.

LOC Deviation:

“LOC Deviation,” shall mean, for units other than wind units, the LOC Deviation shall equal the desired megawatt amount for the resource determined according to the point on the Final Offer curve corresponding to the Real-time Settlement Interval real-time Locational Marginal Price at the resource’s bus and adjusted for any Regulation or Tier 2 Synchronized Reserve assignments and limited to the lesser of the unit’s Economic Maximum or the unit’s Generation Resource Maximum Output, minus the actual output of the unit. For wind units, the LOC Deviation shall mean the deviation of the generating unit’s output equal to the lesser of the PJM forecasted output for the unit or the desired megawatt amount for the resource determined according to the point on the Final Offer curve corresponding to the Real-time Settlement Interval integrated real-time Locational Marginal Price at the resource’s bus, and shall be limited to the lesser of the unit’s Economic Maximum or the unit’s Generation Resource Maximum Output, minus the actual output of the unit.

Locational Deliverability Area (LDA):

“Locational Deliverability Area” or “LDA” shall mean a geographic area within the PJM Region that has limited transmission capability to import capacity to satisfy such area’s reliability requirement, as determined by the Office of the Interconnection in connection with preparation of the Regional Transmission Expansion Plan, and as specified in Reliability Assurance Agreement, Schedule 10.1.

Locational Deliverability Area Reliability Requirement:

“Locational Deliverability Area Reliability Requirement” shall mean the projected internal capacity in the Locational Deliverability Area plus the Capacity Emergency Transfer Objective for the Delivery Year, as determined by the Office of the Interconnection in connection with preparation of the Regional Transmission Expansion Plan, less the minimum internal resources required for all FRR Entities in such Locational Deliverability Area.

Locational Price Adder:

“Locational Price Adder” shall mean an addition to the marginal value of Unforced Capacity within an LDA as necessary to reflect the price of Capacity Resources required to relieve applicable binding locational constraints.

Locational Reliability Charge:

“Locational Reliability Charge” shall have the meaning specified in the Reliability Assurance Agreement.

Locational UCAP:

“Locational UCAP” shall mean unforced capacity that a Member with available uncommitted capacity sells in a bilateral transaction to a Member that previously committed capacity through an RPM Auction but now requires replacement capacity to fulfill its RPM Auction commitment.

The Locational UCAP Seller retains responsibility for performance of the resource providing such replacement capacity.

Locational UCAP Seller:

"Locational UCAP Seller" shall mean a Member that sells Locational UCAP.

Long-lead Project:

"Long-lead Project" shall have the same meaning provided in the Operating Agreement.

Long-Term Firm Point-To-Point Transmission Service:

"Long-Term Firm Point-To-Point Transmission Service" shall mean firm Point-To-Point Transmission Service under Tariff, Part II with a term of one year or more.

Loss Price:

"Loss Price" shall mean the loss component of the Locational Marginal Price, which is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource based on the effect of increased generation from or consumption by the resource on transmission losses, calculated as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

M2M Flowgate:

"M2M Flowgate" shall have the meaning provided in the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.

Maintenance Adder:

"Maintenance Adder" shall mean an adder that may be included to account for variable operation and maintenance expenses in a Market Seller's Fuel Cost Policy. The Maintenance Adder is calculated in accordance with the applicable provisions of PJM Manual 15, and may only include expenses incurred as a result of electric production.

Manual Load Dump Action:

"Manual Load Dump Action" shall mean an Operating Instruction, as defined by NERC, from PJM to shed firm load when the PJM Region cannot provide adequate capacity to meet the PJM Region's load and tie schedules, or to alleviate critically overloaded transmission lines or other equipment.

Manual Load Dump Warning:

“Manual Load Dump Warning” shall mean a notification from PJM to warn Members of an increasingly critical condition of present operations that may require manually shedding load.

Marginal Value:

“Marginal Value” shall mean the incremental change in system dispatch costs, measured as a $/MW value incurred by providing one additional MW of relief to the transmission constraint.

Market Monitor:

“Market Monitor**”** means the head of the Market Monitoring Unit.

Market Monitoring Unit or MMU:

“Market Monitoring Unit” or “MMU” means the independent Market Monitoring Unit defined in 18 CFR § 35.28(a)(7) and established under the PJM Market Monitoring Plan (Attachment M) to the PJM Tariff that is responsible for implementing the Market Monitoring Plan, including the Market Monitor. The Market Monitoring Unit may also be referred to as the IMM or Independent Market Monitor for PJM

Market Monitoring Unit Advisory Committee or MMU Advisory Committee:

“Market Monitoring Unit Advisory Committee” or “MMU Advisory Committee” shall mean the committee established under Tariff, Attachment M, section III.H.

Market Operations Center:

“Market Operations Center” shall mean the equipment, facilities and personnel used by or on behalf of a Market Participant to communicate and coordinate with the Office of the Interconnection in connection with transactions in the PJM Interchange Energy Market or the operation of the PJM Region.

Market Participant:

“Market Participant” shall mean a Market Buyer, a Market Seller, an Economic Load Response Participant, or all three, except when such term is used in Tariff, Attachment M, in which case Market Participant shall mean an entity that generates, transmits, distributes, purchases, or sells electricity, ancillary services, or any other product or service provided under the PJM Tariff or Operating Agreement within, into, out of, or through the PJM Region, but it shall not include an Authorized Government Agency that consumes energy for its own use but does not purchase or sell energy at wholesale.

Market Participant Energy Injection:

“Market Participant Energy Injection” shall mean transactions in the Day-ahead Energy Market and Real-time Energy Market, including but not limited to Day-ahead generation schedules, real-time generation output, Increment Offers, internal bilateral transactions and import transactions, as further described in the PJM Manuals.

Market Participant Energy Withdrawal:

“Market Participant Energy Withdrawal” shall mean transactions in the Day-ahead Energy Market and Real-time Energy Market, including but not limited to Demand Bids, Decrement Bids, real-time load (net of Behind The Meter Generation expected to be operating, but not to be less than zero), internal bilateral transactions and Export Transactions, as further described in the PJM Manuals.

Market Seller Offer Cap:

“Market Seller Offer Cap” shall mean a maximum offer price applicable to certain Market Sellers under certain conditions, as determined in accordance with Tariff, Attachment DD. section 6 and Tariff, Attachment M-Appendix, section II.E.

Market Violation:

“Market Violation” shall mean a tariff violation, violation of a Commission-approved order, rule or regulation, market manipulation, or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies, as defined in 18 C.F.R. § 35.28(b)(8).

Material Modification:

“Material Modification” shall mean any modification to an Interconnection Request that has a material adverse effect on the cost or timing of Interconnection Studies related to, or any Network Upgrades or Local Upgrades needed to accommodate, any Interconnection Request with a later Queue Position.

Maximum Daily Starts:

“Maximum Daily Starts” shall mean the maximum number of times that a generating unit can be started in an Operating Day under normal operating conditions.

Maximum Emergency:

“Maximum Emergency” shall mean the designation of all or part of the output of a generating unit for which the designated output levels may require extraordinary procedures and therefore are available to the Office of the Interconnection only when the Office of the Interconnection declares a Maximum Generation Emergency and requests generation designated as Maximum Emergency to run. The Office of the Interconnection shall post on the PJM website the aggregate amount of megawatts that are classified as Maximum Emergency.

Maximum Facility Output:

"Maximum Facility Output" shall mean the maximum (not nominal) net electrical power output in megawatts, specified in the Interconnection Service Agreement, after supply of any parasitic or host facility loads, that a Generation Interconnection Customer's Customer Facility is expected to produce, provided that the specified Maximum Facility Output shall not exceed the output of the proposed Customer Facility that Transmission Provider utilized in the System Impact Study.

Maximum Generation Emergency:

"Maximum Generation Emergency" shall mean an Emergency declared by the Office of the Interconnection to address either a generation or transmission emergency in which the Office of the Interconnection anticipates requesting one or more Generation Capacity Resources, or Non-Retail Behind The Meter Generation resources to operate at its maximum net or gross electrical power output, subject to the equipment stress limits for such Generation Capacity Resource or Non-Retail Behind The Meter resource in order to manage, alleviate, or end the Emergency.

Maximum Generation Emergency Alert:

"Maximum Generation Emergency Alert" shall mean an alert issued by the Office of the Interconnection to notify PJM Members, Transmission Owners, resource owners and operators, customers, and regulators that a Maximum Generation Emergency may be declared, for any Operating Day in either, as applicable, the Day-ahead Energy Market or the Real-time Energy Market, for all or any part of such Operating Day.

Maximum Run Time:

"Maximum Run Time" shall mean the maximum number of hours a generating unit can run over the course of an Operating Day, as measured by PJM's State Estimator.

Maximum Weekly Starts:

"Maximum Weekly Starts" shall mean the maximum number of times that a generating unit can be started in one week, defined as the 168 hour period starting Monday 0001 hour, under normal operating conditions.

Member:

"Member" shall have the meaning provided in the Operating Agreement.

Merchant A.C. Transmission Facilities:

"Merchant A.C. Transmission Facility" shall mean Merchant Transmission Facilities that are alternating current (A.C.) transmission facilities, other than those that are Controllable A.C. Merchant Transmission Facilities.

Merchant D.C. Transmission Facilities:

"Merchant D.C. Transmission Facilities" shall mean direct current (D.C.) transmission facilities that are interconnected with the Transmission System pursuant to Tariff, Part IV and Part VI.

Merchant Network Upgrades:

"Merchant Network Upgrades" shall mean additions to, or modifications or replacements of, physical facilities of the Interconnected Transmission Owner that, on the date of the pertinent Transmission Interconnection Customer's Upgrade Request, are part of the Transmission System or are included in the Regional Transmission Expansion Plan.

Merchant Transmission Facilities:

"Merchant Transmission Facilities" shall mean A.C. or D.C. transmission facilities that are interconnected with or added to the Transmission System pursuant to Tariff, Part IV and Part VI and that are so identified in Tariff, Attachment T, provided, however, that Merchant Transmission Facilities shall not include (i) any Customer Interconnection Facilities, (ii) any physical facilities of the Transmission System that were in existence on or before March 20, 2003 ; (iii) any expansions or enhancements of the Transmission System that are not identified as Merchant Transmission Facilities in the Regional Transmission Expansion Plan and Attachment T to the Tariff, or (iv) any transmission facilities that are included in the rate base of a public utility and on which a regulated return is earned.

Merchant Transmission Provider:

"Merchant Transmission Provider" shall mean an Interconnection Customer that (1) owns, controls, or controls the rights to use the transmission capability of, Merchant D.C. Transmission Facilities and/or Controllable A.C. Merchant Transmission Facilities that connect the Transmission System with another control area, (2) has elected to receive Transmission Injection Rights and Transmission Withdrawal Rights associated with such facility pursuant to Tariff, Part IV, section 36, and (3) makes (or will make) the transmission capability of such facilities available for use by third parties under terms and conditions approved by the Commission and stated in the Tariff, consistent with Tariff, section 38.

Metering Equipment:

"Metering Equipment" shall mean all metering equipment installed at the metering points designated in the appropriate appendix to an Interconnection Service Agreement.

Minimum Annual Resource Requirement:

"Minimum Annual Resource Requirement" shall mean, for Delivery Years through May 31, 2017, the minimum amount of capacity that PJM will seek to procure from Annual Resources for the PJM Region and for each Locational Deliverability Area for which the Office of the

Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for such Delivery Year. For the PJM Region, the Minimum Annual Resource Requirement shall be equal to the RTO Reliability Requirement minus [the Sub-Annual Resource Reliability Target for the RTO in Unforced Capacity]. For an LDA, the Minimum Annual Resource Requirement shall be equal to the LDA Reliability Requirement minus [the LDA CETL] minus [the Sub-Annual Resource Reliability Target for such LDA in Unforced Capacity]. The LDA CETL may be adjusted pro rata for the amount of load served under the FRR Alternative.

Minimum Down Time:

For all generating units that are not combined cycle units, "Minimum Down Time" shall mean the minimum number of hours under normal operating conditions between unit shutdown and unit startup, calculated as the shortest time difference between the unit's generator breaker opening and after the unit's generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero. For combined cycle units, "Minimum Down Time" shall mean the minimum number of hours between the last generator breaker opening and after first combustion turbine generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero.

Minimum Extended Summer Resource Requirement:

"Minimum Extended Summer Resource Requirement" shall mean, for Delivery Years through May 31, 2017, the minimum amount of capacity that PJM will seek to procure from Extended Summer Demand Resources and Annual Resources for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for such Delivery Year. For the PJM Region, the Minimum Extended Summer Resource Requirement shall be equal to the RTO Reliability Requirement minus [the Limited Demand Resource Reliability Target for the PJM Region in Unforced Capacity]. For an LDA, the Minimum Extended Summer Resource Requirement shall be equal to the LDA Reliability Requirement minus [the LDA CETL] minus [the Limited Demand Resource Reliability Target for such LDA in Unforced Capacity]. The LDA CETL may be adjusted pro rata for the amount of load served under the FRR Alternative.

Minimum Generation Emergency:

"Minimum Generation Emergency" shall mean an Emergency declared by the Office of the Interconnection in which the Office of the Interconnection anticipates requesting one or more generating resources to operate at or below Normal Minimum Generation, in order to manage, alleviate, or end the Emergency.

Minimum Participation Requirements:

"Minimum Participation Requirements" shall mean a set of minimum training, risk management, communication and capital or collateral requirements required for Participants in the PJM Markets, as set forth herein and in the Form of Annual Certification set forth as Tariff, Attachment Q, Appendix 1. Participants transacting in FTRs in certain circumstances will be required to demonstrate additional risk management procedures and controls as further set forth in the Annual Certification found in Tariff, Attachment Q, Appendix 1.

Minimum Run Time:

For all generating units that are not combined cycle units, “Minimum Run Time” shall mean the minimum number of hours a unit must run, in real-time operations, from the time after generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero, to the time of generator breaker opening, as measured by PJM's State Estimator. For combined cycle units, “Minimum Run Time” shall mean the time period after the first combustion turbine generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero, and the last generator breaker opening as measured by PJM’s State Estimator.

MISO:

“MISO” shall mean the Midcontinent Independent System Operator, Inc. or any successor thereto.

MOPR Floor Offer Price:

“MOPR Floor Offer Price” shall mean a minimum offer price applicable to certain Market Seller’s Capacity Resources under certain conditions, as determined in accordance with Tariff, Attachment DD. section 5.14(h).

Multi-Driver Project:

“Multi-Driver Project” shall have the same meaning provided in the Operating Agreement.

Native Load Customers:

“Native Load Customers” shall mean the wholesale and retail power customers of a Transmission Owner on whose behalf the Transmission Owner, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate the Transmission Owner’s system to meet the reliable electric needs of such customers.

NERC:

“NERC” shall mean the North American Electric Reliability Corporation or any successor thereto.

NERC Interchange Distribution Calculator:

"NERC Interchange Distribution Calculator" shall mean the NERC mechanism that is in effect and being used to calculate the distribution of energy, over specific transmission interfaces, from energy transactions.

Net Benefits Test:

"Net Benefits Test" shall mean a calculation to determine whether the benefits of a reduction in price resulting from the dispatch of Economic Load Response exceeds the cost to other loads resulting from the billing unit effects of the load reduction, as specified in Operating Agreement, Schedule 1, section 3.3A.4 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.4.

Net Cost of New Entry:

"Net Cost of New Entry" shall mean the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset.

Net Obligation:

"Net Obligation" shall mean the amount owed to PJMSettlement and PJM for purchases from the PJM Markets, Transmission Service, (under Tariff, Parts II and III , and other services pursuant to the Agreements, after applying a deduction for amounts owed to a Participant by PJMSettlement as it pertains to monthly market activity and services. Should other markets be formed such that Participants may incur future Obligations in those markets, then the aggregate amount of those Obligations will also be added to the Net Obligation.

Net Sell Position:

"Net Sell Position" shall mean the amount of Net Obligation when Net Obligation is negative.

Network Customer:

"Network Customer" shall mean an entity receiving transmission service pursuant to the terms of the Transmission Provider's Network Integration Transmission Service under Tariff, Part III.

Network External Designated Transmission Service:

"Network External Designated Transmission Service" shall have the meaning set forth in Reliability Assurance Agreement, Article I.

Network Integration Transmission Service:

"Network Integration Transmission Service" shall mean the transmission service provided under Tariff, Part III.

Network Load:

“Network Load” shall mean the load that a Network Customer designates for Network Integration Transmission Service under Tariff, Part III. The Network Customer’s Network Load shall include all load (including losses, Non-Dispatched Charging Energy, and Load Serving Charging Energy) served by the output of any Network Resources designated by the Network Customer. A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery. Where an Eligible Customer has elected not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangements under Tariff, Part II for any Point-To-Point Transmission Service that may be necessary for such non-designated load. Network Load shall not include Dispatched Charging Energy.

Network Operating Agreement:

“Network Operating Agreement” shall mean an executed agreement that contains the terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Network Integration Transmission Service under Tariff, Part III.

Network Operating Committee:

“Network Operating Committee” shall mean a group made up of representatives from the Network Customer(s) and the Transmission Provider established to coordinate operating criteria and other technical considerations required for implementation of Network Integration Transmission Service under Tariff, Part III.

Network Resource:

“Network Resource” shall mean any designated generating resource owned, purchased, or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer’s Network Load on a non-interruptible basis, except for purposes of fulfilling obligations under a reserve sharing program.

Network Service User:

“Network Service User” shall mean an entity using Network Transmission Service.

Network Transmission Service:

“Network Transmission Service” shall mean transmission service provided pursuant to the rates, terms and conditions set forth in Tariff, Part III, or transmission service comparable to such service that is provided to a Load Serving Entity that is also a Transmission Owner.

Network Upgrades:

"Network Upgrades" shall mean modifications or additions to transmission-related facilities that are integrated with and support the Transmission Provider's overall Transmission System for the general benefit of all users of such Transmission System. Network Upgrades shall include:

(i) **Direct Connection Network Upgrades** which are Network Upgrades that are not part of an Affected System; only serve the Customer Interconnection Facility; and have no impact or potential impact on the Transmission System until the final tie-in is complete. Both Transmission Provider and Interconnection Customer must agree as to what constitutes Direct Connection Network Upgrades and identify them in the Interconnection Construction Service Agreement, Schedule D. If the Transmission Provider and Interconnection Customer disagree about whether a particular Network Upgrade is a Direct Connection Network Upgrade, the Transmission Provider must provide the Interconnection Customer a written technical explanation outlining why the Transmission Provider does not consider the Network Upgrade to be a Direcct Connection Network Upgrade within 15 days of its determination.

(ii) **Non-Direct Connection Network Upgrades** which are parallel flow Network Upgrades that are not Direct Connection Network Upgrades.

Neutral Party:

"Neutral Party" shall have the meaning provided in Tariff, Part I, section 9.3(v).

New Entry Capacity Resource:

"New Entry Capacity Resource" shall mean (1) a Capacity Resource with State Subsidy or (2) a natural gas-fired combined cycle resource or combustion turbine resource, that has not cleared in an RPM Auction pursuant to its Sell Offer at or above its resource-specific MOPR Floor Offer Price or the applicable default New Entry MOPR Floor Offer Price. Notwithstanding the foregoing, any Capacity Resource that previously cleared an RPM Auction before it became entitled to receive a State Subsidy shall not be deemed a New Entry Capacity Resource.

New PJM Zone(s):

"New PJM Zone(s)" shall mean the Zone included in the Tariff, along with applicable Schedules and Attachments, for Commonwealth Edison Company, The Dayton Power and Light Company and the AEP East Operating Companies (Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company).

New Service Customers:

"New Service Customers" shall mean all customers that submit an Interconnection Request, a Completed Application, or an Upgrade Request that is pending in the New Services Queue.

New Service Request:

“New Service Request” shall mean an Interconnection Request, a Completed Application, or an Upgrade Request.

New Services Queue:

“New Service Queue” shall mean all Interconnection Requests, Completed Applications, and Upgrade Requests that are received within each six-month period ending on April 30 and October 31 of each year shall collectively comprise a New Services Queue.

New Services Queue Closing Date:

“New Services Queue Closing Date” shall mean each April 30 and October 31 shall be the Queue Closing Date for the New Services Queue comprised of Interconnection Requests, Completed Applications, and Upgrade Requests received during the six-month period ending on such date.

New York ISO or NYISO:

“New York ISO” or “NYISO” shall mean the New York Independent System Operator, Inc. or any successor thereto.

Nodal Reference Price:

The “Nodal Reference Price” at each location shall mean the 97th percentile price differential between day-ahead and real-time prices experienced over the corresponding two-month reference period in the prior calendar year. Reference periods will be Jan-Feb, Mar-Apr, May-Jun, Jul-Aug, Sept-Oct, Nov-Dec. For any given current-year month, the reference period months will be the set of two months in the prior calendar year that include the month corresponding to the current month. For example, July and August 2003 would each use July-August 2002 as their reference period.

No-load Cost:

“No-load Cost” shall mean the hourly cost required to create the starting point of a monotonically increasing incremental offer curve for a generating unit.

Nominal Rated Capability:

“Nominal Rated Capability” shall mean the nominal maximum rated capability in megawatts of a Transmission Interconnection Customer’s Customer Facility or the nominal increase in transmission capability in megawatts of the Transmission System resulting from the interconnection or addition of a Transmission Interconnection Customer’s Customer Facility, as determined in accordance with pertinent Applicable Standards and specified in the Interconnection Service Agreement.

Nominated Demand Resource Value:

"Nominated Demand Resource Value" shall mean the amount of load reduction that a Demand Resource commits to provide either through direct load control, firm service level or guaranteed load drop programs. For existing Demand Resources, the maximum Nominated Demand Resource Value is limited, in accordance with the PJM Manuals, to the value appropriate for the method by which the load reduction would be accomplished, at the time the Base Residual Auction or Incremental Auction is being conducted.

Nominated Energy Efficiency Value:

"Nominated Energy Efficiency Value" shall mean the amount of load reduction that an Energy Efficiency Resource commits to provide through installation of more efficient devices or equipment or implementation of more efficient processes or systems.

Non-Dispatched Charging Energy:

"Non-Dispatched Charging Energy" shall mean all Direct Charging Energy that an Energy Storage Resource Model Participant receives from the electric grid that is not otherwise Dispatched Charging Energy.

Non-Firm Point-To-Point Transmission Service:

"Non-Firm Point-To-Point Transmission Service" shall mean Point-To-Point Transmission Service under the Tariff that is reserved and scheduled on an as-available basis and is subject to Curtailment or Interruption as set forth in Tariff, Part II, section 14.7. Non-Firm Point-To-Point Transmission Service is available on a stand-alone basis for periods ranging from one hour to one month.

Non-Firm Sale:

"Non-Firm Sale" shall mean an energy sale for which receipt or delivery may be interrupted for any reason or no reason, without liability on the part of either the buyer or seller.

Non-Firm Transmission Withdrawal Rights:

"No-Firm Transmission Withdrawal Rights" shall mean the rights to schedule energy withdrawals from a specified point on the Transmission System. Non-Firm Transmission Withdrawal Rights may be awarded only to a Merchant D.C. Transmission Facility that connects the Transmission System to another control area. Withdrawals scheduled using Non-Firm Transmission Withdrawal Rights have rights similar to those under Non-Firm Point-to-Point Transmission Service.

Non-Performance Charge:

"Non-Performance Charge" shall mean the charge applicable to Capacity Performance Resources as defined in Tariff, Attachment DD, section 10A(e).

Nonincumbent Developer:

"Nonincumbent Developer" shall have the same meaning provided in the Operating Agreement.

Non-Regulatory Opportunity Cost:

"Non-Regulatory Opportunity Cost" shall mean the difference between (a) the forecasted cost to operate a specific generating unit when the unit only has a limited number of starts or available run hours resulting from (i) the physical equipment limitations of the unit, for up to one year, due to original equipment manufacturer recommendations or insurance carrier restrictions, (ii) a fuel supply limitation, for up to one year, resulting from an event of Catastrophic Force Majeure; and, (b) the forecasted future Locational Marginal Price at which the generating unit could run while not violating such limitations. Non-Regulatory Opportunity Cost therefore is the value associated with a specific generating unit's lost opportunity to produce energy during a higher valued period of time occurring within the same period of time in which the unit is bound by the referenced restrictions, and is reflected in the rules set forth in PJM Manual 15. Non-Regulatory Opportunity Costs shall be limited to those resources which are specifically delineated in Operating Agreement, Schedule 2.

Non-Retail Behind The Meter Generation:

"Non-Retail Behind The Meter Generation" shall mean Behind the Meter Generation that is used by municipal electric systems, electric cooperatives, or electric distribution companies to serve load.

Non-Synchronized Reserve:

"Non-Synchronized Reserve" shall mean the reserve capability of non-emergency generation resources that can be converted fully into energy within ten minutes of a request from the Office of the Interconnection dispatcher, and is provided by equipment that is not electrically synchronized to the Transmission System.

Non-Synchronized Reserve Event:

"Non-Synchronized Reserve Event" shall mean a request from the Office of the Interconnection to generation resources able and assigned to provide Non-Synchronized Reserve in one or more specified Reserve Zones or Reserve Sub-zones, within ten minutes to increase the energy output by the amount of assigned Non-Synchronized Reserve capability.

Non-Variable Loads:

"Non-Variable Loads" shall have the meaning specified in Operating Agreement, Schedule 1, section 1.5A.6, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.5A.6.

Non-Zone Network Load:

“Non-Zone Network Load shall mean Network Load that is located outside of the PJM Region.

Normal Maximum Generation:

“Normal Maximum Generation” shall mean the highest output level of a generating resource under normal operating conditions.

Normal Minimum Generation:

“Normal Minimum Generation” shall mean the lowest output level of a generating resource under normal operating conditions.

Definitions – R - S

Ramping Capability:

"Ramping Capability" shall mean the sustained rate of change of generator output, in megawatts per minute.

Real-time Congestion Price:

"Real-time Congestion Price" shall mean the Congestion Price resulting from the Office of the Interconnection's dispatch of the PJM Interchange Energy Market in the Operating Day.

Real-time Loss Price:

"Real-time Loss Price" shall mean the Loss Price resulting from the Office of the Interconnection's dispatch of the PJM Interchange Energy Market in the Operating Day.

Real-time Energy Market:

"Real-time Energy Market" shall mean the purchase or sale of energy and payment of Transmission Congestion Charges for quantity deviations from the Day-ahead Energy Market in the Operating Day.

Real-time Offer:

"Real-time Offer" shall mean a new offer or an update to a Market Seller's existing cost-based or market-based offer for a clock hour, submitted for use after the close of the Day-ahead Energy Market.

Real-time Prices:

"Real-time Prices" shall mean the Locational Marginal Prices resulting from the Office of the Interconnection's dispatch of the PJM Interchange Energy Market in the Operating Day.

Real-time Settlement Interval:

"Real-time Settlement Interval" shall mean the interval used by settlements, which shall be every five minutes.

Real-time System Energy Price:

"Real-time System Energy Price" shall mean the System Energy Price resulting from the Office of the Interconnection's dispatch of the PJM Interchange Energy Market in the Operating Day.

Reasonable Efforts:

"Reasonable Efforts" shall mean, with respect to any action required to be made, attempted, or taken by an Interconnection Party or by a Construction Party under Tariff, Part IV or Part VI, an Interconnection Service Agreement, or a Construction Service Agreement, such efforts as are timely and consistent with Good Utility Practice and with efforts that such party would undertake for the protection of its own interests.

Receiving Party:

"Receiving Party" shall mean the entity receiving the capacity and energy transmitted by the Transmission Provider to Point(s) of Delivery.

Referral:

"Referral" shall mean a formal report of the Market Monitoring Unit to the Commission for investigation of behavior of a Market Participant, of behavior of PJM, or of a market design flaw, pursuant to Tariff, Attachment M, section IV.I.

Reference Resource:

"Reference Resource" shall mean a combustion turbine generating station, configured with a single General Electric Frame 7HA turbine with evaporative cooling, Selective Catalytic Reduction technology all CONE Areas, dual fuel capability, and a heat rate of 9.134 Mmbtu/MWh.

Regional Entity:

"Regional Entity" shall have the same meaning specified in the Operating Agreement.

Regional Transmission Expansion Plan:

"Regional Transmission Expansion Plan" shall mean the plan prepared by the Office of the Interconnection pursuant to Operating Agreement, Schedule 6 for the enhancement and expansion of the Transmission System in order to meet the demands for firm transmission service in the PJM Region.

Regional Transmission Group (RTG):

"Regional Transmission Group" or "RTG" shall mean a voluntary organization of transmission owners, transmission users and other entities approved by the Commission to efficiently coordinate transmission planning (and expansion), operation and use on a regional (and interregional) basis.

Regulation:

"Regulation" shall mean the capability of a specific generation resource or Demand Resource with appropriate telecommunications, control and response capability to separately increase and decrease its output or adjust load in response to a regulating control signal, in accordance with the specifications in the PJM Manuals.

Regulation Zone:

"Regulation Zone" shall mean any of those one or more geographic areas, each consisting of a combination of one or more Control Zone(s) as designated by the Office of the Interconnection in the PJM Manuals, relevant to provision of, and requirements for, regulation service.

Relevant Electric Retail Regulatory Authority:

"Relevant Electric Retail Regulatory Authority" shall mean an entity that has jurisdiction over and establishes prices and policies for competition for providers of retail electric service to end-customers, such as the city council for a municipal utility, the governing board of a cooperative utility, the state public utility commission or any other such entity.

Reliability Assurance Agreement or PJM Reliability Assurance Agreement:

"Reliability Assurance Agreement" or "PJM Reliability Assurance Agreement" shall mean that certain Reliability Assurance Agreement Among Load Serving Entities in the PJM Region, on file with FERC as PJM Interconnection L.L.C. Rate Schedule FERC No. 44, and as amended from time to time thereafter.

Reliability Pricing Model Auction:

"Reliability Pricing Model Auction" or "RPM Auction" shall mean the Base Residual Auction or any Incremental Auction, or, for the 2016/2017 and 2017/2018 Delivery Years, any Capacity Performance Transition Incremental Auction.

Required Transmission Enhancements:

"Regional Transmission Enhancements" shall mean enhancements and expansions of the Transmission System that (1) a Regional Transmission Expansion Plan developed pursuant to Operating Agreement, Schedule 6 or (2) any joint planning or coordination agreement between PJM and another region or transmission planning authority set forth in Tariff, Schedule 12-Appendix B ("Appendix B Agreement") designates one or more of the Transmission Owner(s) to construct and own or finance. Required Transmission Enhancements shall also include enhancements and expansions of facilities in another region or planning authority that meet the definition of transmission facilities pursuant to FERC's Uniform System of Accounts or have been classified as transmission facilities in a ruling by FERC addressing such facilities constructed pursuant to an Appendix B Agreement cost responsibility for which has been assigned at least in part to PJM pursuant to such Appendix B Agreement.

Reserved Capacity:

"Reserved Capacity" shall mean the maximum amount of capacity and energy that the Transmission Provider agrees to transmit for the Transmission Customer over the Transmission Provider's Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Tariff, Part II. Reserved Capacity shall be expressed in terms of whole megawatts on a sixty (60) minute interval (commencing on the clock hour) basis.

Reserve Penalty Factor:

"Reserve Penalty Factor" shall mean the cost, in $/MWh, associated with being unable to meet a specific reserve requirement in a Reserve Zone or Reserve Sub-zone. A Reserve Penalty Factor will be defined for each reserve requirement in a Reserve Zone or Reserve Sub-zone.

Reserve Sub-zone:

"Reserve Sub-zone" shall mean any of those geographic areas wholly contained within a Reserve Zone, consisting of a combination of a portion of one or more Control Zone(s) as designated by the Office of the Interconnection in the PJM Manuals, relevant to provision of, and requirements for, reserve service.

Reserve Zone:

"Reserve Zone" shall mean any of those geographic areas consisting of a combination of one or more Control Zone(s), as designated by the Office of the Interconnection in the PJM Manuals, relevant to provision of, and requirements for, reserve service.

Residual Auction Revenue Rights:

"Residual Auction Revenue Rights" shall mean incremental stage 1 Auction Revenue Rights created within a Planning Period by an increase in transmission system capability, including the return to service of existing transmission capability, that was not modeled pursuant to Operating Agreement, Schedule 1, section 7.5 and the parallel provisions of Tariff, Attachment K-Appendix, section 7.5 in compliance with Operating Agreement, Schedule 1, section 7.4.2 (h) and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.2(h), and, if modeled, would have increased the amount of stage 1 Auction Revenue Rights allocated pursuant to Operating Agreement, Schedule 1, section 7.4.2 and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.2; provided that, the foregoing notwithstanding, Residual Auction Revenue Rights shall exclude: 1) Incremental Auction Revenue Rights allocated pursuant to Tariff, Part VI; and 2) Auction Revenue Rights allocated to entities that are assigned cost responsibility pursuant to Operating Agreement, Schedule 6 for transmission upgrades that create such rights.

Residual Metered Load:

"Residual Metered Load" shall mean all load remaining in an electric distribution company's fully metered franchise area(s) or service territory(ies) after all nodally priced load of entities serving load in such area(s) or territory(ies) has been carved out.

Resource Substitution Charge:

"Resource Substitution Charge" shall mean a charge assessed on Capacity Market Buyers in an Incremental Auction to recover the cost of replacement Capacity Resources.

Revenue Data for Settlements:

"Revenue Data for Settlements" shall mean energy quantities used in accounting and billing as determined pursuant to Tariff, Attachment K-Appendix and the corresponding provisions of Operating Agreement, Schedule 1.

RPM Seller Credit:

"RPM Seller Credit" shall mean an additional form of Unsecured Credit defined in Tariff, Attachment Q, section IV.

Scheduled Incremental Auctions:

"Scheduled Incremental Auctions" shall refer to the First, Second, or Third Incremental Auction.

Schedule of Work:

"Schedule of Work" shall mean that schedule attached to the Interconnection Construction Service Agreement setting forth the timing of work to be performed by the Constructing Entity pursuant to the Interconnection Construction Service Agreement, based upon the Facilities Study and subject to modification, as required, in accordance with Transmission Provider's scope change process for interconnection projects set forth in the PJM Manuals.

Scope of Work:

"Scope of Work" shall mean that scope of the work attached as a schedule to the Interconnection Construction Service Agreement and to be performed by the Constructing Entity(ies) pursuant to the Interconnection Construction Service Agreement, provided that such Scope of Work may be modified, as required, in accordance with Transmission Provider's scope change process for interconnection projects set forth in the PJM Manuals.

Seasonal Capacity Performance Resource:

"Seasonal Capacity Performance Resource" shall have the same meaning specified in Tariff, Attachment DD, section 5.5A.

Secondary Systems:

"Secondary Systems" shall mean control or power circuits that operate below 600 volts, AC or DC, including, but not limited to, any hardware, control or protective devices, cables, conductors, electric raceways, secondary equipment panels, transducers, batteries, chargers, and voltage and current transformers.

Second Incremental Auction:

"Second Incremental Auction" shall mean an Incremental Auction conducted ten months before the Delivery Year to which it relates**.**

Security:

"Security" shall mean the security provided by the New Service Customer pursuant to Tariff, section 212.4 or Tariff, Part VI, section 213.4 to secure the New Service Customer's responsibility for Costs under the Interconnection Service Agreement or Upgrade Construction Service Agreement and Tariff, Part VI, section 217.

Segment:

"Segment" shall have the same meaning as described in Operating Agreement, Schedule 1, section 3.2.3(e).

Self-Supply:

"Self-Supply" shall mean Capacity Resources secured by a Load-Serving Entity, by ownership or contract, outside a Reliability Pricing Model Auction, and used to meet obligations under this Attachment or the Reliability Assurance Agreement through submission in a Base Residual Auction or an Incremental Auction of a Sell Offer indicating such Market Seller's intent that such Capacity Resource be Self-Supply. Self-Supply may be either committed regardless of clearing price or submitted as a Sell Offer with a price bid. A Load Serving Entity's Sell Offer with a price bid for an owned or contracted Capacity Resource shall not be deemed "Self-Supply," unless it is designated as Self-Supply and used by the LSE to meet obligations under this Attachment or the Reliability Assurance Agreement.

Self-Supply Entity:

"Self-Supply Entity" shall mean the following types of Load Serving Entity that operate under long-standing business models: single customer entity, public power entity, or vertically integrated utility, where "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 or receives any cost recovery for such generation through bilateral contracts; "single customer entity" means a Load Serving Entity that serves at retail only customers that are under common control with such Load Serving Entity, where such control means holding 51% or more of the voting securities or voting interests of the Load Serving Entity and all its retail customers; and "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.

Sell Offer:

"Sell Offer" shall mean an offer to sell Capacity Resources in a Base Residual Auction, Incremental Auction, or Reliability Backstop Auction.

Service Agreement:

"Service Agreement" shall mean the initial agreement and any amendments or supplements thereto entered into by the Transmission Customer and the Transmission Provider for service under the Tariff.

Service Commencement Date:

"Service Commencement Date" shall mean the date the Transmission Provider begins to provide service pursuant to the terms of an executed Service Agreement, or the date the Transmission Provider begins to provide service in accordance with Tariff, Part II, section 15.3 or Tariff, Part III, section 29.1.

Short-Term Firm Point-To-Point Transmission Service:

"Short-Term Firm Point-To-Point Transmission Service" shall mean Firm Point-To-Point Transmission Service under Tariff, Part II with a term of less than one year.

Short-term Project:

"Short-term Project" shall have the same meaning provided in the Operating Agreement.

Short-Term Resource Procurement Target:

"Short-Term Resource Procurement Target" shall mean, for Delivery Years through May 31, 2018, as to the PJM Region, for purposes of the Base Residual Auction, 2.5% of the PJM Region Reliability Requirement determined for such Base Residual Auction, for purposes of the First Incremental Auction, 2% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction; and, for purposes of the Second Incremental Auction, 1.5% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction; and, as to any Zone, an allocation of the PJM Region Short-Term Resource Procurement Target based on the Preliminary Zonal Forecast Peak Load, reduced by the amount of load served under the FRR Alternative. For any LDA, the LDA Short-Term Resource Procurement Target shall be the sum of the Short-Term Resource Procurement Targets of all Zones in the LDA.

Short-Term Resource Procurement Target Applicable Share:

"Short-Term Resource Procurement Target Applicable Share" shall mean, for Delivery Years through May 31, 2018: (i) for the PJM Region, as to the First and Second Incremental Auctions, 0.2 times the Short-Term Resource Procurement Target used in the Base Residual Auction and, as to the Third Incremental Auction for the PJM Region, 0.6 times such target; and (ii) for an

LDA, as to the First and Second Incremental Auctions, 0.2 times the Short-Term Resource Procurement Target used in the Base Residual Auction for such LDA and, as to the Third Incremental Auction, 0.6 times such target.

Site:

"Site" shall mean all of the real property, including but not limited to any leased real property and easements, on which the Customer Facility is situated and/or on which the Customer Interconnection Facilities are to be located.

Small Commercial Customer:

"Small Commercial Customer," as used in RAA, Schedule 6 and Tariff, Attachment DD-1, shall mean a commercial retail electric end-use customer of an electric distribution company that participates in a mass market demand response program under the jurisdiction of a RERRA and satisfies the definition of a "small commercial customer" under the terms of the applicable RERRA's program, provided that the customer has an annual peak demand no greater than 100kW.

Small Generation Resource:

"Small Generation Resource" shall mean an Interconnection Customer's device of 20 MW or less for the production and/or storage for later injection of electricity identified in an Interconnection Request, but shall not include the Interconnection Customer's Interconnection Facilities. This term shall include Energy Storage Resources and/or other devices for storage for later injection of energy.

Small Inverter Facility:

"Small Inverter Facility" shall mean an Energy Resource that is a certified small inverter-based facility no larger than 10 kW.

Small Inverter ISA:

"Small Inverter ISA" shall mean an agreement among Transmission Provider, Interconnection Customer, and Interconnected Transmission Owner regarding interconnection of a Small Inverter Facility under Tariff, Part IV, section 112B.

Special Member:

"Special Member" shall mean an entity that satisfies the requirements of Operating Agreement, Schedule 1, section 1.5A.02, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.5A.02, or the special membership provisions established under the Emergency Load Response and Pre-Emergency Load Response Programs.

Spot Market Backup:

“Spot Market Backup” shall mean the purchase of energy from, or the delivery of energy to, the PJM Interchange Energy Market in quantities sufficient to complete the delivery or receipt obligations of a bilateral contract that has been curtailed or interrupted for any reason.

Spot Market Energy:

“Spot Market Energy” shall mean energy bought or sold by Market Participants through the PJM Interchange Energy Market at System Energy Prices determined as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

Start Additional Labor Costs:

“Start Additional Labor Costs” shall mean additional labor costs for startup required above normal station manning levels.

Start-Up Costs:

“Start-Up Costs” shall mean the unit costs to bring the boiler, turbine and generator from shutdown conditions to the point after breaker closure which is typically indicated by telemetered or aggregated state estimator megawatts greater than zero and is determined based on the cost of start fuel, total fuel-related cost, performance factor, electrical costs (station service), start maintenance adder, and additional labor cost if required above normal station manning. Start-Up Costs can vary with the unit offline time being categorized in three unit temperature conditions: hot, intermediate and cold.

State:

“State” shall mean the District of Columbia and any State or Commonwealth of the United States.

State Commission:

“State Commission**”** shall mean any state regulatory agency having jurisdiction over retail electricity sales in any State in the PJM Region.

State Estimator:

“State Estimator” shall mean the computer model of power flows specified in Operating Agreement, Schedule 1, section 2.3 and the parallel provisions of Tariff, Attachment K-Appendix, section 2.3.

State Subsidy:

"State Subsidy" shall mean a direct or indirect payment, concession, rebate, subsidy, non-bypassable consumer charge, or other financial benefit that is as a result of any action, mandated process, or sponsored process of a state government, a political subdivision or agency of a state, or an electric cooperative formed pursuant to state law, and that

(1) is derived from or connected to the procurement of (a) electricity or electric generation capacity sold at wholesale in interstate commerce, or (b) an attribute of the generation process for electricity or electric generation capacity sold at wholesale in interstate commerce; or

(2) will support the construction, development, or operation of a new or existing Capacity Resource; or

(3) could have the effect of allowing the unit to clear in any PJM capacity auction.

Notwithstanding the foregoing, State Subsidy shall not include (a) payments, 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 designed to incent siting facilities in that county or locality rather than another county or locality; (b) state action that imposes a tax or assesses a charge utilizing the parameters of a regional program on a given set of resources notwithstanding the tax or cost having indirect benefits on resources not subject to the tax or cost (e.g., Regional Greenhouse Gas Initiative); (c) any indirect benefits to a Capacity Resource as a result of any transmission project approved as part of the Regional Transmission Expansion Plan; (d) any contract, legally enforceable obligation, or rate pursuant to the Public Utility Regulatory Policies Act or any other state-administered federal regulatory program (e.g., the Cross-State Air Pollution Rule); (e) any state-directed default service procurement program that is competitively procured without regard to resource fuel type (e.g., New Jersey Basic Generation Service, Maryland Standard Offer Service); (f) any revenues for providing capacity as part of an FRR Capacity Plan or through bilateral transactions with FRR Entities; or (g) any voluntary and arm's length bilateral transaction (including but not limited to those reported pursuant to Tariff, Attachment DD, section 4.6), such as a power purchase agreement or other similar contract where the buyer is a Self-Supply Entity and the transaction is (1) a short term transaction (one-year or less) or (2) a long-term transaction that is the result of a competitive process that was not fuel-specific and is not used for the purpose of supporting uneconomic construction, development, or operation of the subject Capacity Resource, provided however that if the Self-Supply Entity is responsible for offering the Capacity Resource into an RPM Auction, the specified amount of installed capacity purchased by such Self-Supply Entity shall be considered to receive a State Subsidy in the same manner, under the same conditions, and to the same extent as any other Capacity Resource of a Self-Supply Entity.

State of Charge:

"State of Charge" shall mean the quantity of physical energy stored in an Energy Storage Resource Model Participant in proportion to its maximum State of Charge capability. State of Charge is quantified as defined in the PJM Manuals.

State of Charge Management:

“State of Charge Management” shall mean the control of State of Charge of an Energy Storage Resource Market Participant using minimum and maximum charge and discharge limits, changes in operating mode, charging and discharging offer curves, and self-scheduling of non-dispatchable purchases and sales of energy in the PJM markets. State of Charge Management shall not interfere with an Energy Storage Resource Model Participant’s obligation to follow PJM dispatch, consistent with all other resources.

Station Power:

“Station Power” shall mean energy used for operating the electric equipment on the site of a generation facility located in the PJM Region or for the heating, lighting, air-conditioning and office equipment needs of buildings on the site of such a generation facility that are used in the operation, maintenance, or repair of the facility. Station Power does not include any energy (i) used to power synchronous condensers; (ii) used for pumping at a pumped storage facility; (iii) used in association with restoration or black start service; or (iv) that is Direct Charging Energy.

Sub-Annual Resource Constraint:

“Sub-Annual Resource Constraint” shall mean, for the 2017/2018 Delivery Year and for FRR Capacity Plans the 2017/2018 and 2018/2019 Delivery Years, for the PJM Region or for each LDA for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for a Delivery Year, a limit on the total amount of Unforced Capacity that can be committed as Limited Demand Resources and Extended Summer Demand Resources for the 2017/2018 Delivery Year in the PJM Region or in such LDA, calculated as the Sub-Annual Resource Reliability Target for the PJM Region or for such LDA, respectively, minus the Short-Term Resource Procurement Target for the PJM Region or for such LDA, respectively.

Sub-Annual Resource Price Decrement:

“Sub-Annual Resource Price Decrement” shall mean, for the 2017/2018 Delivery Year, a difference between the clearing price for Extended Summer Demand Resources and the clearing price for Annual Resources, representing the cost to procure additional Annual Resources out of merit order when the Sub-Annual Resource Constraint is binding.

Sub-Annual Resource Reliability Target:

“Sub-Annual Reliability Target” for the PJM Region or an LDA, shall mean the maximum amount of the combination of Extended Summer Demand Resources and Limited Demand Resources in Unforced Capacity determined by PJM to be consistent with the maintenance of reliability, stated in Unforced Capacity, that shall be used to calculate the Minimum Annual Resource Requirement for Delivery Years through May 31, 2017 and the Sub-Annual Resource Constraint for the 2017/2018 and 2018/2019 Delivery Years. As more fully set forth in the PJM Manuals, PJM calculates the Sub-Annual Resource Reliability Target, by first determining a reference annual loss of load expectation (“LOLE”) assuming no Demand Resources. The calculation for the unconstrained portion of the PJM Region uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast and iteratively shifting the load distributions to result in the Installed Reserve Margin established for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). The calculation for each relevant LDA uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Capacity Emergency Transfer Objective study for the Delivery Year in question). For the relevant LDA calculation, the weekly capacity distributions are adjusted to reflect the Capacity Emergency Transfer Limit for the Delivery Year in question.

For both the PJM Region and LDA analyses, PJM then models the commitment of varying amounts of DR (displacing otherwise committed generation) as interruptible from May 1 through October 31 and unavailable from November 1 through April 30 and calculates the LOLE at each DR level. The Extended Summer DR Reliability Target is the DR amount, stated as a percentage of the unrestricted peak load, that produces no more than a ten percent increase in the LOLE, compared to the reference value. The Sub-Annual Resource Reliability Target shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the DR Factor] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

Sub-meter:

"Sub-meter" shall mean a metering point for electricity consumption that does not include all electricity consumption for the end-use customer as defined by the electric distribution company account number. PJM shall only accept sub-meter load data from end-use customers for measurement and verification of Regulation service as set forth in the Economic Load Response rules and PJM Manuals.

Summer-Period Capacity Performance Resource:

"Summer-Period Capacity Performance Resource" shall have the same meaning specified in Tariff, Attachment DD, section 5.5A.

Surplus Interconnection Customer:

"Surplus Interconnection Customer" shall mean either an Interconnection Customer whose Generating Facility is already interconnected to the PJM Transmission System or one of its affiliates, or an unaffiliated entity that submits a Surplus Interconnection Request to utilize Surplus Interconnection Service within the Transmission System in the PJM Region. A Surplus Interconnection Customer is not a New Service Customer.

Surplus Interconnection Request:

"Surplus Interconnection Request" shall mean a request submitted by a Surplus Interconnection Customer, pursuant to Tariff, Attachment RR, to utilize Surplus Interconnection Service within the Transmission System in the PJM Region. A Surplus Interconnection Request is not a New Service Request.

Surplus Interconnection Service:

"Surplus Interconnection Service" shall mean any unneeded portion of Interconnection Service established in an Interconnection Service Agreement, such that if Surplus Interconnection Service is utilized, the total amount of Interconnection Service at the Point of Interconnection would remain the same.

Switching and Tagging Rules:

"Switching and Tagging Rules" shall mean the switching and tagging procedures of Interconnected Transmission Owners and Interconnection Customer as they may be amended from time to time.

Synchronized Reserve:

"Synchronized Reserve" shall mean the reserve capability of generation resources that can be converted fully into energy or Demand Resources whose demand can be reduced within ten minutes from the request of the Office of the Interconnection dispatcher, and is provided by equipment that is electrically synchronized to the Transmission System.

Synchronized Reserve Event:

"Synchronized Reserve Event" shall mean a request from the Office of the Interconnection to generation resources and/or Demand Resources able, assigned or self-scheduled to provide Synchronized Reserve in one or more specified Reserve Zones or Reserve Sub-zones, within ten minutes, to increase the energy output or reduce load by the amount of assigned or self-scheduled Synchronized Reserve capability.

Synchronized Reserve Requirement:

"Synchronized Reserve Requirement" shall mean the megawatts required to be maintained in a Reserve Zone or Reserve Sub-zone as Synchronized Reserve, absent any increase to account for additional reserves scheduled to address operational uncertainty. The Synchronized Reserve Requirement is calculated in accordance with the PJM Manuals.

System Condition:

"System Condition" shall mean a specified condition on the Transmission Provider's system or on a neighboring system, such as a constrained transmission element or flowgate, that may trigger Curtailment of Long-Term Firm Point-to-Point Transmission Service using the curtailment priority pursuant to Tariff, Part II, section 13.6. Such conditions must be identified in the Transmission Customer's Service Agreement.

System Energy Price:

"System Energy Price" shall mean the energy component of the Locational Marginal Price, which is the price at which the Market Seller has offered to supply an additional increment of energy from a resource, calculated as specified in Operating Agreement, Schedule 1, section 2 and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

System Impact Study:

"System Impact Study" shall mean an assessment by the Transmission Provider of (i) the adequacy of the Transmission System to accommodate a Completed Application, an Interconnection Request or an Upgrade Request, (ii) whether any additional costs may be incurred in order to provide such transmission service or to accommodate an Interconnection Request, and (iii) with respect to an Interconnection Request, an estimated date that an Interconnection Customer's Customer Facility can be interconnected with the Transmission System and an estimate of the Interconnection Customer's cost responsibility for the interconnection; and (iv) with respect to an Upgrade Request, the estimated cost of the requested system upgrades or expansion, or of the cost of the system upgrades or expansion, necessary to provide the requested incremental rights.

System Protection Facilities:

"System Protection Facilities" shall refer to the equipment required to protect (i) the Transmission System, other delivery systems and/or other generating systems connected to the Transmission System from faults or other electrical disturbance occurring at or on the Customer Facility, and (ii) the Customer Facility from faults or other electrical system disturbance occurring on the Transmission System or on other delivery systems and/or other generating systems to which the Transmission System is directly or indirectly connected. System Protection Facilities shall include such protective and regulating devices as are identified in the Applicable Technical Requirements and Standards or that are required by Applicable Laws and Regulations or other Applicable Standards, or as are otherwise necessary to protect personnel and equipment and to minimize deleterious effects to the Transmission System arising from the Customer Facility.

5.6 Sell Offers

Sell Offers shall be submitted or withdrawn via the internet site designated by the Office of the Interconnection, under the procedures and time schedule set forth in the PJM Manuals.

5.6.1 Specifications

A Sell Offer shall state quantities in increments of 0.1 megawatts and shall specify, as appropriate:

a) Identification of the Generation Capacity Resource, Demand Resource, Capacity Storage Resource or Energy Efficiency Resource on which such Sell Offer is based;

b) Minimum and maximum megawatt quantity of installed capacity that the Capacity Market Seller is willing to offer (notwithstanding such specification, the product offered shall be Unforced Capacity), or designate as Self-Supply, from a Generation Capacity Resource;

i) Price, in dollars and cents per megawatt-day, that will be accepted by the Capacity Market Seller for the megawatt quantity of Unforced Capacity offered from such Generation Capacity Resource.

ii) The Sell Offer may take the form of offer segments with varying price-quantity pairs for varying output levels from the underlying resource, but may not take the form of an offer curve with nonzero slope.

c) EFORd of each Generation Capacity Resource offered.

i) If a Capacity Market Seller is offering such resource in a Base Residual Auction, First Incremental Auction, Second Incremental Auction, or Conditional Incremental Auction occurring before the Third Incremental Auction, the Capacity Market Seller shall specify the EFORd to apply to the offer.

ii) If a Capacity Market Seller is committing the resource as Self-Supply, the Capacity Market Seller shall specify the EFORd to apply to the commitment.

iii) The EFORd applied to the Third Incremental Auction will be the final EFORd established by the Office of the Interconnection six (6) months prior to the Delivery Year, based on the actual EFORd in the PJM Region during the 12-month period ending September 30 that last precedes such Delivery Year.

d) The Nominated Demand Resource Value for each Demand Resource offered and the Nominated Energy Efficiency Value for each Energy Efficiency Resource offered. The Office of the Interconnection shall, in both cases, convert such value to an Unforced Capacity basis by multiplying such value by the DR Factor (for Delivery Years through May 31, 2018) times the Forecast Pool Requirement. Demand Resources shall specify the LDA in which the Demand Resource is located, including the location of such resource within any Zone that includes more than one LDA as identified on Schedule 10.1 of the RAA.

e) For Delivery Years through May 31, 2018, a Demand Resource with the potential to qualify as two or more of a Limited Demand Resource, Extended Summer Demand Resource or Annual Demand Resource may submit separate but coupled Sell Offers for each Demand Resource type for which it qualifies at different prices and the auction clearing algorithm will select the Sell Offer that yields the least-cost solution. For such coupled Demand Resource offers, the offer price of an Annual Demand Resource offer must be at least $.01 per MW-day greater than the offer price of a coupled Extended Summer Demand Resource offer and the offer price of a Extended Summer Demand Resource offer must be at least $.01 per MW-day greater than the offer price of a coupled Limited Demand Resource offer.

f) For a Qualifying Transmission Upgrade, the Sell Offer shall identify such upgrade, and the Office of the Interconnection shall determine and certify the increase in CETL provided by such upgrade. The Capacity Market Seller may offer the upgrade with an associated increase in CETL to an LDA in accordance with such certification, including an offer price that will be accepted by the Capacity Market Seller, stated in dollars and cents per megawatt-day as a price difference between a Capacity Resource located outside such an LDA and a Capacity Resource located inside such LDA; and the increase in CETL into such LDA to be provided by such Qualifying Transmission Upgrade, as certified by the Office of the Interconnection.

g) For the 2018/2019 and 2019/2020 Delivery Years, each Capacity Market Seller owning or controlling a resource that qualifies as both a Base Capacity Resource and a Capacity Performance Resource may submit separate but coupled Sell Offers for such resource as a Base Capacity Resource and as a Capacity Performance Resource, at different prices, and the auction clearing algorithm will select the Sell Offer that yields the least-cost solution. Submission of a coupled Base Capacity Resource Sell Offer shall be mandatory for any Capacity Performance Resource Sell Offer that exceeds a Sell Offer Price equal to the applicable Net Cost of New Entry times the Balancing Ratio as provided for in section 6.4. For such coupled Sell Offers, the offer price of a Capacity Performance Resource offer must be at least $.01 per MW-day greater than the offer price of a coupled Base Capacity Resource offer.

(h) For the 2018/2019 Delivery Year and subsequent Delivery Years, a Capacity Market Seller that owns or controls one or more Capacity Storage Resources, Intermittent Resources, Demand Resources, or Energy Efficiency Resources may submit a Sell Offer as a Capacity Performance Resource in a MW quantity consistent with their average expected output during peak-hour periods. Alternatively, for the 2018/2019 Delivery Year and subsequent Delivery Years, a Capacity Market Seller that owns or controls one or more Capacity Storage Resources, Intermittent Resources, Demand Resources, Energy Efficiency Resources, or Environmentally-Limited Resources may submit a Sell Offer which represents the aggregated Unforced Capacity value of such resources, where such Sell Offer shall be considered to be located in the smallest modeled LDA common to the aggregated resources. Such aggregated resources shall be owned by or under contract to the Capacity Market Seller, including all such resources obtained through bilateral contract and reported to the Office of the Interconnection in accordance with the Office of the Interconnection’s rules related to its Capacity Exchange tools. If any of the commercially aggregated resources in such Sell Offer are subject to the Minimum Floor Offer Price pursuant to Tariff, Attachment DD, section 5.14(h), the Capacity Market Seller that owns or controls such resources may submit a Sell Offer with a Minimum Floor Offer Price of no lower than the time and MW-weighted average of the applicable MOPR Floor Offer Prices (zero if not applicable) of the aggregated resources in such Sell Offer.

(i) For the 2020/2021 Delivery Year and subsequent Delivery Years, a Capacity Market Seller that owns or controls a resource that qualifies as a Summer-Period Capacity Performance Resource may submit a Sell Offer as a Capacity Performance Resource in a MW quantity consistent with the average expected output of such resource during peak-hour periods, and may submit a separate Sell Offer as a Summer-Period Capacity Performance Resource in a MW quantity consistent with the average expected output of such resource during summer peak-hour periods, provided the total Sell Offer MW quantity submitted as both a Capacity Performance Resource and a Summer-Period Capacity Performance Resource does not exceed the Unforced Capacity value of the resource. For the 2020/2021 Delivery Year and subsequent Delivery Years, a Capacity Market Seller that owns or controls a resource that qualifies as a Winter-Period Capacity Performance Resource may submit a Sell Offer as a Capacity Performance Resource in a MW quantity consistent with the average expected output of such resource during peak-hour periods, and may submit a separate Sell Offer as a Winter-Period Capacity Performance Resource in a MW quantity consistent with the average expected output of such resource during winter peak-hour periods, provided the total Sell Offer MW quantity submitted as both a Capacity Performance Resource and a Winter-Period Capacity Performance Resource does not exceed the Unforced Capacity value of the resource. Each segment of a Seasonal Capacity Performance Resource Sell Offer must be submitted as a flexible Sell Offer segment with the minimum MW quantity offered set to zero.

5.6.2 Compliance with PJM Credit Policy

Capacity Market Sellers shall comply with the provisions of the PJM Credit Policy as set forth in Attachment Q to this Tariff, including the provisions specific to the Reliability Pricing Model, prior to submission of Sell Offers in any Reliability Pricing Model Auction. A Capacity Market Seller desiring to submit a Credit-Limited Offer shall specify in its Sell Offer the maximum auction credit requirement, in dollars, and the maximum amount of Unforced Capacity, in megawatts, applicable to its Sell Offer.

5.6.3 [reserved]

5.6.4 Qualifying Transmission Upgrades

A Qualifying Transmission Upgrade may not be the subject of any Sell Offer in a Base Residual Auction unless it has been approved by the Office of the Interconnection, including certification of the increase in Import Capability to be provided by such Qualifying Transmission Upgrade, no later than 45 days prior to such Base Residual Auction. No such approval shall be granted unless, at a minimum, a Facilities Study Agreement has been executed with respect to such upgrade, and such upgrade conforms to all applicable standards of the Regional Transmission Expansion Plan process.

5.6.5 Market-based Sell Offers

Subject to section 6, a Market Seller authorized by FERC to sell electric generating capacity at market-based prices, or that is not required to have such authorization, may submit Sell Offers that specify market-based prices in any Base Residual Auction or Incremental Auction.

5.6.6 Availability of Capacity Resources for Sale

(a) The Office of the Interconnection shall determine the quantity of megawatts of available installed capacity that each Capacity Market Seller must offer in any RPM Auction pursuant to Section 6.6 of Attachment DD, through verification of the availability of megawatts of installed capacity from: (i) all Generation Capacity Resources owned by or under contract to the Capacity Market Seller, including all Generation Capacity Resources obtained through bilateral contract; (ii) the results of prior Reliability Pricing Model Auctions, if any, for such Delivery Year (including consideration of any restriction imposed as a consequence of a prior failure to offer); and (iii) such other information as may be available to the Office of the Interconnection. The Office of the Interconnection shall reject Sell Offers or portions of Sell Offers for Capacity Resources in excess of the quantity of installed capacity from such Capacity Market Seller's Capacity Resource that it determines to be available for sale.

(b) The Office of the Interconnection shall determine the quantity of installed capacity available for sale in a Base Residual Auction or Incremental Auction as of the beginning of the period during which Buy Bids and Sell Offers are accepted for such auction, as applicable, in accordance with the time schedule set forth in the PJM Manuals. Removal of a resource from Capacity Resource status shall not be reflected in the determination of available installed capacity unless the associated unit-specific bilateral transaction is approved, the designation of such resource (or portion thereof) as a network resource for the external load is demonstrated to the Office of the Interconnection, or equivalent evidence of a firm external sale is provided prior to the deadline established therefor. The determination of available installed capacity shall also take into account, as they apply in proportion to the share of each resource owned or controlled by a Capacity Market Seller, any approved capacity modifications, and existing capacity commitments established in a prior RPM Auction, an FRR Capacity Plan, Locational UCAP transactions and/or replacement capacity transactions under this Attachment DD. To enable the Office of the Interconnection to make this determination, no bilateral transactions for Capacity Resources applicable to the period covered by an auction will be processed from the beginning of the period for submission of Sell Offers and Buy Bids, as appropriate, for that auction until completion of the clearing determination for such auction. Processing of such bilateral transactions will reconvene once clearing for that auction is completed. A Generation Capacity Resource located in the PJM Region shall not be removed from Capacity Resource status to the extent the resource is committed to service of PJM loads as a result of an RPM Auction, FRR Capacity Plan, Locational UCAP transaction and/or by designation as a replacement resource under this Attachment DD.

(c) In order for a bilateral transaction for the purchase and sale of a Capacity Resource to be processed by the Office of the Interconnection, both parties to the transaction must notify the Office of the Interconnection of the transfer of the Capacity Resource from the seller to the buyer in accordance with procedures established by the Office of the Interconnection and set forth in the PJM Manuals. If a material change with respect to any of the prerequisites for the application of Section 5.6.6 to the Generation Capacity Resource occurs, the Capacity

Resource Owner shall immediately notify the Market Monitoring Unit and the Office of the Interconnection.

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. 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.

b) Resource Make-Whole Payments

If a Sell Offer specifies a minimum block, and only a portion of such block is needed to clear the market in a Base Residual or Incremental Auction, the MW portion of such Sell Offer needed to clear the market shall clear, and such Sell Offer shall set the marginal value of system capacity. In addition, the Capacity Market Seller shall receive a Resource Make-Whole Payment equal to the Capacity Resource Clearing Price in such auction times the difference between the Sell Offer's minimum block MW quantity and the Sell Offer's cleared MW quantity. If the Sell Offer price of a cleared Seasonal Capacity Performance Resource exceeds the applicable Capacity Resource Clearing Price, the Capacity Market Seller shall receive a Resource Make-Whole Payment equal to the difference between the Sell Offer price and Capacity Resource Clearing Price in such RPM Auction. The cost for any such Resource Make-Whole Payments required in a Base Residual Auction or Incremental Auction for adjustment of prior capacity commitments shall be collected pro rata from all LSEs in the LDA in which such payments were made, based on their Daily Unforced Capacity Obligations. The cost for any such Resource Make-Whole

Payments required in an Incremental Auction for capacity replacement shall be collected from all Capacity Market Buyers in the LDA in which such payments were made, on a pro-rata basis based on the MWs purchased in such auction.

c) New Entry Price Adjustment

A Capacity Market Seller that submits a Sell Offer based on a Planned Generation Capacity Resource that clears in the BRA for a Delivery Year may, at its election, submit Sell Offers with a New Entry Price Adjustment in the BRAs for the two immediately succeeding Delivery Years if:

1. Such Capacity Market Seller provides notice of such election at the time it submits its Sell Offer for such resource in the BRA for the first Delivery Year for which such resource is eligible to be considered a Planned Generation Capacity Resource. When the Capacity Market Seller provides notice of such election, it must specify whether its Sell Offer is contingent upon qualifying for the New Entry Price Adjustment. The Office of the Interconnection shall not clear such contingent Sell Offer if it does not qualify for the New Entry Price Adjustment.

2. All or any part of a Sell Offer from the Planned Generation Capacity Resource submitted in accordance with section 5.14(c)(1) is the marginal Sell Offer that sets the Capacity Resource Clearing Price for the LDA.

3. Acceptance of all or any part of a Sell Offer that meets the conditions in section 5.14(c)(1)-(2) in the BRA increases the total Unforced Capacity committed in the BRA (including any minimum block quantity) for the LDA in which such Resource will be located from a megawatt quantity below the LDA Reliability Requirement, minus the Short Term Resource Procurement Target, to a megawatt quantity at or above a megawatt quantity at the price-quantity point on the VRR Curve at which the price is 0.40 times the applicable Net CONE divided by (one minus the pool-wide average EFORd).

4. Such Capacity Market Seller submits Sell Offers in the BRA for the two immediately succeeding Delivery Years for the entire Unforced Capacity of such Generation Capacity Resource committed in the first BRA under section 5.14(c)(1)-(2) equal to the lesser of: A) the price in such seller’s Sell Offer for the BRA in which such resource qualified as a Planned Generation Capacity Resource that satisfies the conditions in section 5.14(c)(1)-(3); or B) 0.90 times the Net CONE applicable in the first BRA in which such Planned Generation Capacity Resource meeting the conditions in section 5.14(c)(1)-(3) cleared, on an Unforced Capacity basis, for such LDA.

5. If the Sell Offer is submitted consistent with section 5.14(c)(1)-(4) the foregoing conditions, then:

(i) in the first Delivery Year, the Resource sets the Capacity Resource Clearing Price for the LDA and all cleared resources in the LDA receive the Capacity Resource Clearing Price set by the Sell Offer as the marginal offer, in accordance with sections 5.12(a) and 5.14(a).

(ii) in either of the subsequent two BRAs, if any part of the Sell Offer from the Resource clears, it shall receive the Capacity Resource Clearing Price for such LDA for its cleared capacity and for any additional minimum block quantity pursuant to section 5.14(b); or

(iii) if the Resource does not clear, it shall be deemed resubmitted at the highest price per MW-day at which the megawatt quantity of Unforced Capacity of such Resource that cleared the first-year BRA will clear the subsequent-year BRA pursuant to the optimization algorithm described in section 5.12(a) of this Attachment, and

(iv) the resource with its Sell Offer submitted shall clear and shall be committed to the PJM Region in the amount cleared, plus any additional minimum-block quantity from its Sell Offer for such Delivery Year, but such additional amount shall be no greater than the portion of a minimum-block quantity, if any, from its first-year Sell Offer satisfying section 5.14(c)(1)-(3) that is entitled to compensation pursuant to section 5.14(b) of this Attachment; and

(v) the Capacity Resource Clearing Price, and the resources cleared, shall be re-determined to reflect the resubmitted Sell Offer. In such case, the Resource for which the Sell Offer is submitted pursuant to section 5.14(c)(1)-(4) shall be paid for the entire committed quantity at the Sell Offer price that it initially submitted in such subsequent BRA. The difference between such Sell Offer price and the Capacity Resource Clearing Price (as well as any difference between the cleared quantity and the committed quantity), will be treated as a Resource Make-Whole Payment in accordance with Section 5.14(b). Other capacity resources that clear the BRA in such LDA receive the Capacity Resource Clearing Price as determined in Section 5.14(a).

6. The failure to submit a Sell Offer consistent with Section 5.14(c)(i)-(iii) in the BRA for Delivery Year 3 shall not retroactively revoke the New Entry Price Adjustment for Delivery Year 2. However, the failure to submit a Sell Offer consistent with section 5.14(c)(4) in the BRA for Delivery Year 2 shall make the resource ineligible for the New Entry Pricing Adjustment for Delivery Years 2 and 3.

7. For each Delivery Year that the foregoing conditions are satisfied, the Office of the Interconnection shall maintain and employ in the auction clearing for such LDA a separate VRR Curve, notwithstanding the outcome of the test referenced in Section 5.10(a)(ii) of this Attachment.

8. On or before August 1, 2012, PJM shall file with FERC under FPA section 205, as determined necessary by PJM following a stakeholder process, tariff changes to establish a long-term auction process as a not unduly discriminatory means to provide adequate

long-term revenue assurances to support new entry, as a supplement to or replacement of this New Entry Price Adjustment.

d) Qualifying Transmission Upgrade Payments

A Capacity Market Seller that submitted a Sell Offer based on a Qualifying Transmission Upgrade that clears in the Base Residual Auction shall receive a payment equal to the Capacity Resource Clearing Price, including any Locational Price Adder, of the LDA into which the Qualifying Transmission Upgrade is to increase Capacity Emergency Transfer Limit, less the Capacity Resource Clearing Price, including any Locational Price Adder, of the LDA from which the upgrade was to provide such increased CETL, multiplied by the megawatt quantity of increased CETL cleared from such Sell Offer. Such payments shall be reflected in the Locational Price Adder determined as part of the Final Zonal Capacity Price for the Zone associated with such LDAs, and shall be funded through a reduction in the Capacity Transfer Rights allocated to Load-Serving Entities under section 5.15, as set forth in that section. PJMSettlement shall be the Counterparty to any cleared capacity transaction resulting from a Sell Offer based on a Qualifying Transmission Upgrade.

e) Locational Reliability Charge

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. PJMSettlement shall be the Counterparty to the LSEs' obligations to pay, and payments of, Locational Reliability Charges.

f) The Office of the Interconnection shall determine Zonal Capacity Prices in accordance with the following, based on the optimization algorithm:

i) The Office of the Interconnection shall calculate and post the Preliminary Zonal Capacity Prices for each Delivery Year following the Base Residual Auction for such Delivery Year. The Preliminary Zonal Capacity Price for each Zone shall be the sum of: 1) the marginal value of system capacity for the PJM Region, without considering locational constraints; 2) the Locational Price Adder, if any, for the LDA in which such Zone is located; provided however, that if the Zone contains multiple LDAs with different Capacity Resource Clearing Prices, the Zonal Capacity Price shall be a weighted average of the Capacity Resource Clearing Prices for such LDAs, weighted by the Unforced Capacity of Capacity Resources cleared in each such LDA; 3) an adjustment, if required, to account for adders paid to Annual Resources and Extended Summer Demand Resources in the LDA for which the zone is located; 4) an adjustment, if required, to account for Resource Make-Whole Payments; and (5) an adjustment, if required to provide sufficient revenue for payment of any PRD Credits, all as determined in accordance with the optimization algorithm.

ii) The Office of the Interconnection shall calculate and post the Adjusted Zonal Capacity Price following each Incremental Auction. The Adjusted Zonal Capacity Price for each Zone shall equal the sum of: (1) the average marginal value of system capacity weighted by the Unforced Capacity cleared in all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); (2) the average Locational Price Adder weighted by the Unforced Capacity cleared in all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); (3) an adjustment, if required, to account for adders paid to Annual Resources and Extended Summer Demand Resources for all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); (4) an adjustment, if required, to account for Resource Make-Whole Payments for all actions previously conducted (excluding any Resource Make-Whole Payments to be charged to the buyers of replacement capacity); and (5) an adjustment, if required to provide sufficient revenue for payment of any PRD Credits. The Adjusted Zonal Capacity Price may decrease if Unforced Capacity is decommitted or the Resource Clearing Price decreases in an Incremental Auction.

iii) The Office of the Interconnection shall calculate and post the Final Zonal Capacity Price for each Delivery Year after the final auction is held for such Delivery Year, as set forth above. The Final Zonal Capacity Price for each Zone shall equal the Adjusted Zonal Capacity Price, as further adjusted to reflect any decreases in the Nominated Demand Resource Value of any existing Demand Resource cleared in the Base Residual Auction and Second Incremental Auction.

g) Resource Substitution Charge

Each Capacity Market Buyer in an Incremental Auction securing replacement capacity shall pay a Resource Substitution Charge equal to the Capacity Resource Clearing Price resulting from such auction multiplied by the megawatt quantity of Unforced Capacity purchased by such Market Buyer in such auction.

h) Minimum Offer Price Rule for Certain Capacity Resources

(1) **General Rule.** Any Sell Offer based on either a New Entry Capacity Resource or a Cleared Capacity Resource with a State Subsidy submitted in any RPM Auction shall have an offer price no lower than the applicable MOPR Floor Offer Price, unless the Capacity Market Seller qualifies for an exemption with respect to such Capacity Resource with a State Subsidy prior to the submission of such offer.

(A) Effect of Exemption. To the extent a Sell Offer in any RPM Auction is based on a Capacity Resource with State Subsidy, a combustion turbine resource, or a combined cycle resource and qualifies for any of the exemptions defined in Tariff, Attachment DD, sections 5.14(h)(4)-(8), the Sell Offer for such resource shall not be limited by the MOPR Floor Offer Price.

(B) Effect of Exception. To the extent a Sell Offer in any RPM Auction for any Delivery Year is based on a Capacity Resource with State Subsidy, a combustion turbine resource, or a combined cycle resource for which the Capacity Market Seller obtains, prior to the submission of such offer, a resource-specific exception, such offer may include an offer price below the default MOPR Floor Offer Price applicable to such resource type, but no lower than the resource-specific MOPR Floor Offer Price determined in such exception process.

(C) Process for Establishing a Capacity Resource with a State Subsidy.

(i) By no later than one hundred and twenty (120) 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 certify to the Office of Interconnection, in accordance with the PJM Manuals, whether or not each Capacity Resource (other than Demand Resource and Energy Efficiency Resource) that the Capacity Market Seller intends to offer into the RPM Auction qualifies as a Capacity Resource with a State Subsidy (including by way of Jointly Owned Cross-Subsidized Capacity Resource) and identify (with specificity) any State Subsidy. Capacity Market Sellers that intend to offer a Demand Resource or an Energy Efficiency Resource into the RPM Auction shall certify to the Office of Interconnection, in accordance with the PJM Manuals, whether or not such Demand Resource or Energy Efficiency Resource qualifies as a Capacity Resource with a State Subsidy no later than thirty (30) 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. All Capacity Market Sellers shall be responsible for each certification irrespective of any guidance developed by the Office of the Interconnection and the Market Monitoring Unit. A Capacity Resource shall be deemed a Capacity Resource with State Subsidy if the Capacity Market Seller fails to timely certify whether or not a Capacity Resource is entitled to a State Subsidy, unless the Capacity Market Seller receives a waiver from the Commission or the Capacity Resource previously received a resource-specific exception pursuant to Tariff, Attachment DD, section 5.14(h)(3).

(ii) The requirements in subsection (i) above do not apply to Capacity Resources for which the Market Seller designated whether or not it is subject to a State Subsidy and the associated subsidies to which the Capacity Resource is entitled in a prior Delivery Year, unless there has been a change in the set of those State Subsidy(ies), or for those which are eligible for the Demand Resource or Energy Efficiency exemption, Capacity Storage Resource exemption, Self-Supply Entity exemption, or the Intermittent Resource exemption.

(iii) Once a Capacity Market Seller has certified a Capacity Resource as a Capacity Resource with a State Subsidy, the status of such Capacity Resource will remain unchanged unless and until the Capacity Market Seller (or a subsequent Capacity Market Seller) that owns or controls such Capacity Resource provides a certification of a change in such status, the Office of the Interconnection removes such status, or by FERC order. All Capacity Market Sellers shall have an ongoing obligation to certify to the Office of Interconnection and the Market Monitoring Unit a Capacity Resource's change in status as a Capacity Resource with State Subsidy within 5 days of such change.

(2) **Minimum Offer Price Rule.** Any Sell Offer for a New Entry Capacity Resource or a Cleared Capacity Resource with State Subsidy that does not qualify for any of the exemptions, as defined in Tariff, Attachment DD, sections 5.14(h)(5)-(8), shall have an offer price no lower than the applicable MOPR Floor Offer Price.

(A) New Entry MOPR Floor Offer Price. For a New Entry Capacity Resource the applicable MOPR Floor Offer Price, based on the net cost of new entry for each resource type, shall be, at the election of the Capacity Market Seller, (i) the resource-specific value determined in accordance with the resource-specific MOPR Floor Offer Price process in Tariff, Attachment DD, section 5.14(h)(3) below or (ii) if applicable, the default New Entry MOPR Floor Offer Price for the applicable resource based on the gross cost of new entry values shown in the table below, as adjusted for Delivery Years subsequent to the 2022/2023 Delivery Year, net of estimated net energy and ancillary service revenues for the resource type and Zone in which the resource is located.

Resource Type	**Gross Cost of New Entry (2022/2023 $/ MW-day) (Nameplate)***
Nuclear	$2,000
Coal	$1,068
Combined Cycle	$320
Combustion Turbine	$294
Fixed Solar PV	$290
Tracking Solar PV	$271
Onshore Wind	$420
Offshore Wind	$1,155
Battery Energy Storage	$532
Generation Backed Demand Resource	$254

* The gross cost of new entry values are expressed in dollars per MW-day in terms of nameplate megawatts. The cost of new entry values are ultimately converted to Installed Capacity ("ICAP") MW-day, where the ICAP MW value for fixed Solar PV, tracking Solar PV, Onshore Wind and Offshore Wind is assumed to be 42.0%, 60%, 17.6%, and 26.0%, respectively, of the nameplate rating of these resource types.

The default New Entry MOPR Floor Offer Price for load-backed Demand Resources (i.e., the MW portion of Demand Resources that is not supported by generation) shall be separately determined for each Locational Deliverability Area as the MW-weighted average offer price of load-backed Demand Resources from the most recent three Base Residual Auctions, where the MW weighting shall be determined based on the portion of each Sell Offer for a load-backed portion of the Demand Resource that is supported by end-use customer locations on the registrations used in the pre-registration process for such Base Residual Auctions, as described in the PJM Manuals.

The default New Entry MOPR Floor Offer Price for Energy Efficiency Resources shall be $64/ICAP MW-Day (Net Cost of New Entry).

Commencing with the Base Residual Auction for the 2023/2024 Delivery Year, the Office of the Interconnection shall adjust the default gross costs of new entry in the table above and for load-backed Demand Resources, and post the preliminary estimates of the adjusted applicable default New Entry MOPR Floor Offer Prices 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 default New Entry MOPR Floor Offer Prices for all resource types except for load-backed Demand Resources and Energy Efficiency Resources, the Office of the Interconnection shall adjust the gross costs of new entry utilizing, for combustion turbine and combined cycle resource types, 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 for all other resource types, the "BLS Producer Price Index Turbines and Turbine Generator Sets" component of the Applicable BLS Composite Index used to determine the Variable Resource Requirement Curve shall be replaced with the "BLS Producer Price Index Final Demand, Goods Less Food & Energy, Private Capital Equipment" when adjusting the gross costs of new entry. The resultant value shall then be then adjusted further by a factor of 1.022 for nuclear, coal, combustion turbine, and combine cycle resource types or 1.01 for solar, wind, and storage resource types to reflect the annual decline in bonus depreciation scheduled under federal corporate tax law. Updated estimates of the net energy and ancillary service revenues for each default resource type and applicable Zone, which shall include, but are not limited to, consideration of Fuel Costs, Maintenance Adders and Operating Costs, as applicable, pursuant to Operating Agreement, Schedule 2 shall then be subtracted from the adjusted gross costs of new entry to determine the adjusted New Entry MOPR Floor Offer Price. The net energy and ancillary services revenue is equal to the average of the annual net revenues of the three most recent calendar years preceding the Base Residual Auction, where such annual net revenues shall be determined in accordance with the following and the PJM Manuals:

(i) for nuclear resource type, the net energy and ancillary services revenue estimate shall be determined by the gross energy market revenue determined by the product of [average annual zonal day-ahead LMP times 8,760 hours times the annual average equivalent availability factor of all PJM nuclear resources] minus the total annual cost to produce energy determined by the product of [8,760 hours times the annual average equivalent availability factor of all PJM nuclear resources times $9.02/MWh for a single unit plant or $7.66/MWh for a multi-unit plant] where these hourly cost rates include fuel costs and variable operation and maintenance expenses, inclusive of Maintenance Adder costs, plus an ancillary services revenue of $3,350/MW-year;

(ii) for coal resource type, the net energy and ancillary services revenue estimate shall be determined by a simulated dispatch of a 650 MW coal unit (with heat rate of 8,638 BTU/kWh and variable operations and maintenance variable operation and maintenance expenses, inclusive of Maintenance Adder costs, of $9.50/MWh) using applicable coal prices, as set forth in the PJM Manuals, and an ancillary services revenue of $3,350/MW-year. The unit is committed day-ahead in profitable blocks of at least eight hours, and then committed in real-time for profitable hours if not already committed day ahead;

(iii) for combustion turbine resource type, the net energy and ancillary services revenue estimate shall be determined in a manner consistent with the methodology described in Tariff, Attachment DD, section 5.10(a)(v)(B) for the Reference Resource combustion turbine.

(iv) for combined cycle resource type, the net energy and ancillary services revenue estimate shall be determined in the same manner as that prescribed for a combustion turbine resource type, except that the heat rate assumed for the combined cycle resource shall be 6,553 BTU/kwh, the variable operations and maintenance expenses for such resource, inclusive of Maintenance Adder costs, shall be $2.11/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 Peak-Hour Dispatch, 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 services revenue shall be $3,350/MW-year.

(v) for solar PV resource type, the net energy and ancillary services revenue estimate shall be determined using a solar resource model that provides the average MW output level, expressed as a percentage of nameplate rating, by hour of day (for each of the 24-hours of a day) and by calendar month (for each of the twelve months of a year). The annual net energy market revenues are determined by multiplying the solar output level of each hour by the real-time zonal LMP applicable to such hour with this product summed across all of the hours of an annual period, plus an ancillary services revenue of $3,350/MW-year. Two separate solar resource models are used, one model for a fixed panel resource and a second model for a tracking panel resource;

(vi) for onshore wind resource type, the net energy and ancillary services revenue estimate shall be determined using a wind resource model that provides the average MW output level, expressed as a percentage of nameplate rating, by hour of day (for each of the 24-hours of a day) and by calendar month (for each of the twelve months of a year). The annual energy market revenues are determined by multiplying the wind output level of each hour by the real-time zonal LMP applicable to such hour with this product summed across all of the hours of an annual period, plus an ancillary services revenue of $3,350/MW-year;

(vii) for offshore wind resource type, the net energy and ancillary services revenue estimate shall be the product of [the average annual zonal real-time LMP times 8,760 hours times an assumed annual capacity factor of 45%], plus an ancillary services revenue of $3,350/MW-year;

(viii) for Capacity Storage Resource, the net energy and ancillary services revenue estimate shall be estimated by a simulated dispatch against historical real-time zonal LMPs where the resource is assumed to be dispatched for the four hours of highest LMP of a daily twenty-four hour period if the average LMP of these four hours exceeds 120% of the average LMP of the four lowest LMP hours of the same twenty-four hour period. The net energy market revenues will be determined by the product of [hourly output of 1 MW times the hourly LMP for each hour of assumed discharging] minus the product of [hourly consumption of 1.2 MW times the hourly LMP for each hour of assumed charging] with this net value summed across all of the hours of an annual period, plus an ancillary services revenue of $3,350/MW-year. An 83.3% efficiency of the battery energy storage resource is reflected by assuming each 1.0 MW of discharge requires 1.2 MW of charge; and

(ix) for generation-backed Demand Resource, the net energy and ancillary services revenue estimate shall be zero dollars.

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 gross cost of new entry values. 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 gross cost of new entry values stated in the table above and the default New Entry MOPR Floor Offer Price for Energy Efficiency Resources. 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 gross cost of new entry values or the default New Entry MOPR Floor Offer Price for Energy Efficiency 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.

New Entry Capacity Resources for which there is no default MOPR Floor Offer Price provided in accordance with this section must seek a resource-specific value determined in accordance with the resource-specific MOPR Floor Offer Price process below to participate in an RPM Auction. Failure to obtain a resource-specific MOPR Floor Offer Price will result in the Office of the Interconnection rejecting any Sell Offer based on such resource for the relevant RPM Auction.

(B) Cleared MOPR Floor Offer Prices. For a Cleared Capacity Resource with State Subsidy, the applicable Cleared MOPR Floor Offer Price shall be, at the election of the Capacity Market Seller, (i) based on the resource-specific MOPR Floor Offer Price , as determined in accordance with Tariff, Attachment DD, section 5.14(h)(3) below, or (ii) if available, the default Avoidable Cost Rate for the applicable 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 estimated net energy and ancillary service revenues for that resource type and Zone in which the resource is located.

Existing Resource Type	**Default Gross ACR (2022/2023 ($/MW-day) (Nameplate)***
Nuclear - single	$697
Nuclear - dual	$445
Coal	$80
Combined Cycle	$56
Combustion Turbine	$50
Solar PV (fixed and tracking)	$40
Wind Onshore	$83
Generation-backed Demand Response	$3
Load-backed Demand Response	$0
Energy Efficiency	$0

* The default Avoidable Cost Rate values are expressed in dollars per MW-day in terms of nameplate megawatts. The cost of new entry values are ultimately converted to Installed Capacity (“ICAP”) MW-day, where the ICAP MW value for Solar PV and

Onshore Wind is assumed to be 42.0%, and 17.6%, 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 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 10-year average Handy-Whitman Index in order to adjust the Gross ACR values to account for expected inflation and updated estimates of the net energy and ancillary service revenues, by Zone, for each default resource type, which shall include, but are not limited to, consideration of Fuel Costs, Maintenance Adders and Operating Costs, as applicable, pursuant to Operating Agreement, Schedule 2. The estimates of the net energy and ancillary services revenues shall be determined in a manner consistent with the methodology described in Tariff, Attachment DD, section 5.14(h)(2)(A) and the PJM Manuals.

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 State 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.

Cleared Capacity Resources with State Subsidy for which there is no default MOPR Floor Offer Price provided in accordance with this section must seek a resource-specific value determined in accordance with the resource-specific MOPR Floor Offer Price process below to participate in an RPM Auction. Failure to obtain a resource-specific MOPR Floor Offer Price will result in the Office of the Interconnection rejecting any Sell Offer based on such resource.

(3) Resource-Specific Exception. A Capacity Market Seller intending to submit a Sell Offer in any RPM Auction for a New Entry Capacity Resource or a Cleared Capacity Resource with State Subsidy below the applicable default MOPR Floor Offer Price may, at its election, submit a request for a resource-specific exception for such Capacity Resource. A Sell Offer below the default MOPR Floor Offer Price, but no lower than the resource-specific MOPR Floor Offer Price, shall be permitted if the Capacity Market Seller obtains approval from the Office of the Interconnection or the Commission, prior to the RPM Auction in which it seeks to submit the Sell Offer. Such Sell Offer is permissible because it is consistent with the competitive, cost-based, fixed, net cost were the resource to rely solely on revenues exclusive of any State Subsidy. All supporting data must be provided for all requests. The following requirements shall apply to requests for such determinations:

(A) The Capacity Market Seller shall submit a written request with all of the required documentation as described below and in the PJM Manuals. For such purpose, the Capacity Market Seller shall submit the resource-specific exception request to the Office of the Interconnection and the Market Monitoring Unit 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. 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 default Minimum Floor Offer Prices, determined pursuant to Tariff, Attachment DD, sections 5.14(h)(2)(A) and (B). If the final applicable default Minimum Floor Offer Price 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.

(B) For a resource-specific exception for a New Entry Capacity Resource, 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 Capacity Resource, as well as estimates of offsetting net revenues.

The financial modeling assumptions for calculating Cost of New Entry for Generation Capacity Resources and generation-backed Demand Resources shall be: (i) nominal levelization of gross costs, (ii) asset life of twenty years, (iii) no residual value, (iv) all project costs included with no sunk costs excluded, (v) use first year revenues (which may include revenues from the sale of renewable energy credits for purposes other than state-mandated or state-sponsored programs), and (vi) weighted average cost of capital based on the actual cost of capital for the entity proposing to build the Capacity Resource. Notwithstanding the foregoing, a Capacity Market Seller that seeks to utilize an asset life other than twenty years (but no greater than 35 years) shall provide evidence to support the use of a different asset life, including but not limited to, the asset life term for such resource as utilized in the Capacity Market Seller's financial accounting (*e.g*., independently audited financial statements), or project financing documents for the resource or evidence of actual costs or financing assumptions of recent comparable projects to the extent the seller has not executed project financing for the resource (*e.g*., independent project engineer opinion or manufacturer's performance guarantee), or opinions of third-party experts regarding the reasonableness of the financing assumptions used for the project itself or in comparable projects. Capacity Market Sellers may also rely on evidence presented in federal filings, such as its FERC Form No. 1 or an SEC Form 10-K, to demonstrate an asset life other than 20 years of similar asset projects.

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 exception hereunder. The request also shall identify all revenue sources (exclusive of any State Subsidies) 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. Any evaluation of net revenues should be consistent with Operating Agreement, Schedule 2, including, but not limited to, consideration of Fuel Costs, Maintenance Adders and Operating Costs, as applicable.

The default assumptions for calculating resource-specific Cost of New Entry for Energy Efficiency Resources shall be based on, as supported by documentation provided by the Capacity Market Seller: the nominal-levelized annual cost to implement the Energy Efficiency program or to install the Energy Efficiency measure reflective of the useful life of the implemented Energy Efficiency equipment, and the offsetting savings associated with avoided wholesale energy costs and other claimed savings provided by implementing the Energy Efficiency program or installing the Energy Efficiency measure.

The default assumptions for calculating resource-specific Cost of New Entry for load-backed Demand Resources shall be based on, as supported by documentation provided by the Capacity Market Seller, program costs required for the resource to meet the capacity obligations of a Demand Resource, including all fixed operating and maintenance cost and weighted average cost of capital based on the actual cost of capital for the entity proposing to develop the Demand Resource.

For generation-backed Demand Resources, the determination of a resource-specific MOPR Floor Offer Price shall only consider the resource's costs related to participation in the Reliability Pricing Model and meeting a capacity commitment. The Capacity Market Seller must provide supporting documentation (at the end-use customer level) of the cost associated with participation as a Demand Resource and an attestation from the Demand Resource that all other costs are not related to participation as a Demand Resource, such as the costs associated with installation and operation of the generation unit, and will be accrued and paid regardless of participation in the Reliability Pricing Model. To the extent the Capacity Market Seller includes all costs associated with the generation unit supporting the Demand Resource then demand charge management benefits at the retail level (as supported by documentation at the end-use customer level) may also be considered as an additional offset to such costs. Supporting documentation (at the end-use customer level) may include, but is not limited to, historic end-use customer bills and associated analysis that identifies the annual retail avoided cost from the operation of such generation unit or the business case to support installation of the generator or regulatory requirements where the generator would be required absent participation in the Reliability Pricing Model.

(C) For a Resource-Specific Exception for a Cleared Capacity Resource with State Subsidy that is a generation resource, the Capacity Market Seller shall submit a Sell Offer consistent with the unit-specific Market Seller Offer Cap process pursuant to Tariff, Attachment DD, section 6.8; except that the 10% uncertainty adder may not be included in the "Adjustment Factor." In addition and notwithstanding the requirements of Tariff, Attachment DD, section 6.8, the Capacity Market Seller may, at its election, include in its request for an exception under this subsection documentation to support projected energy and ancillary services markets revenues. Such a request shall identify all revenue sources (exclusive of any State Subsidies) 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. Any evaluation of revenues should include, but would not be not limited to, consideration of Fuel Costs, Maintenance Adders and Operating Costs, as applicable, pursuant to Operating Agreement, Schedule 2.

The resource-specific MOPR Floor Offer Price for a Cleared Capacity Resource with State Subsidy that is a generation-backed Demand Resource will be determined based on only costs associated with the resource participating in the Reliability Pricing Model and satisfying a capacity commitment or, to the extent the Capacity Market Seller includes all costs associated with the generation unit supporting the Demand Resource, then demand charge management benefits at the retail level (as supported by documentation at the end-use customer level) may also be considered as an additional offset to such costs. Supporting documentation (at the end-use customer level) may include but is not limited to, historic end-use customer bills and associated analysis that identifies the annual retail avoided cost from the operation of such generation unit or the business case to support installation of the generator or regulatory requirements where the generator would be required absent participation in the Reliability Pricing Model.

(D) A Sell Offer evaluated at the resource-specific exception 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 default MOPR Floor Offer Price, based on competitive cost advantages relative to the costs estimated 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 estimated by the default MOPR Floor Offer Price. Capacity Market Sellers shall 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 exception by the Office of the Interconnection.

(E) The Capacity Market Seller must submit a sworn, notarized certification of a duly authorized officer, certifying that the officer has personal knowledge of the resource-specific exception request and that to the best of his/her knowledge and belief: (1) the information supplied to the Market Monitoring Unit and the Office of Interconnection to support its request for an exception is true and correct; (2) the Capacity Market Seller has disclosed all material facts relevant to the request for the exception; and (3) the request satisfies the criteria for the exception.

(F) The Market Monitoring Unit shall review, in an open and transparent manner with the Capacity Market Seller and the Office of the Interconnection, 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, in an open and transparent manner, 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. After the Office of the Interconnection determines with the advice and input of Market Monitor, the acceptable minimum Sell Offer, 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, and in making such determination, the Capacity Market Seller may consider the applicable default MOPR Floor Offer Price and may select such default value if it is lower than the resource-specific determination. 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 based on the lower of the applicable default MOPR Floor Offer Price and the resource-specific determination unless and until ordered to do otherwise by FERC.

(4) Competitive Exemption.

(A) A Capacity Resource with State Subsidy may be exempt from the Minimum Offer Price Rule in any RPM Auction if the Capacity Market Seller certifies to the Office of Interconnection, in accordance with the PJM Manuals, that the Capacity Market Seller of such Capacity Resource elects to forego receiving any State 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. Notwithstanding the foregoing, the competitive exemption is not available to Capacity Resources with State Subsidy that (A) are owned or offered by Self-Supply Entities, (B) are no longer entitled to receive a State Subsidy but are still considered a Capacity Resource with State Subsidy solely because they have not cleared an RPM Auction since last receiving a State Subsidy, (C) are Jointly Owned Cross-Subsidized Capacity Resources or is the subject of a bilateral transaction (including but not limited to those reported pursuant to Tariff, Attachment DD, section 4.6) and not all Capacity Market Sellers of the supporting facility unanimously elect the competitive exemption and certify that no State Subsidy will be received associated with supporting the resource, or (D) a natural gas fired combined cycle or combustion turbine resource.

(B) (i) The Capacity Market Seller shall not receive a State Subsidy for any part of the relevant Delivery Year in which it elects a competitive exemption or certifies that it is not a Capacity Resource with State Subsidy. In furtherance of this prohibition, if a Capacity Resource that (1) is a New Entry Capacity Resource that elects the competitive exemption in subsection (4)(A) above and clears an RPM Auction for a given Delivery Year, but prior to the end of that Delivery Year elects to accept a State Subsidy or (2) is not a Capacity Resource with State Subsidy at the time of the RPM Auction for the Delivery Year for which it first cleared an RPM Auction but prior to the end of that Delivery Year receives a State Subsidy for the associated Delivery Year or an earlier Delivery Year, then the Capacity Market Seller of that Capacity Resource shall not receive RPM revenues for any part of that Delivery Year and may not participate in any RPM Auction with such resource, or be eligible to use such resource as replacement capacity starting June 1 of the Delivery Year after the Capacity Market Seller first receives the State Subsidy and continuing for a period of 20 years, except for battery energy storage, for which such participation restriction shall apply for a period of 15 years. A Jointly Owned Cross-Subsidized Capacity Resource that meets the requirements of either of the two preceding subsections (B)(i)(1) or (2), shall not receive RPM revenues for any part of that Delivery Year and may not participate in any RPM Auction or be eligible to be used as replacement capacity starting June 1 of the Delivery Year and continuing for the number of years specified above, after any joint Capacity Market Seller of the underlying facility first receives the State Subsidy. A Capacity Resource with State Subsidy that is the subject of a bilateral transaction that meets the requirements of either of the two preceding subsections (B)(i)(1) or (2) shall not receive RPM revenues for any part of that Delivery Year and may not participate in any RPM Auction or be eligible to be used as replacement capacity starting June 1 of the Delivery Year and continuing for the number of years specified above if any owner or Capacity Market Seller of the facility receives a State Subsidy. The Capacity Market Seller(s) of any such Capacity Resource or Jointly Owned Cross-Subsidized Capacity Resource shall also return to the Office of the Interconnection any revenues paid to such Capacity Resource associated with their capacity commitment for such Delivery Year and shall retain their RPM commitment and associated obligations for such Delivery Year and for any future Delivery Years in which the resource has already secured a capacity commitment, including any Non-Performance Charges relating to the capacity and remain eligible to collect Performance Payments under this Tariff, Attachment DD, section 10A for the relevant Delivery Year and any subsequent Delivery Years for which it already received an RPM commitment. Notwithstanding the foregoing, Capacity

Resources that lose their eligibility to participate in RPM pursuant to this section remain eligible for commitment in an FRR Capacity Plan.

(ii) If any Capacity Resource that has previously cleared an RPM Auction (1) is a Cleared Capacity Resource with State Subsidy that claims the competitive exemption pursuant to subsection (4)(A) above in an RPM Auction and clears such RPM Auction or (2) was not a Capacity Resource with State Subsidy at the time it cleared an RPM Auction for a given Delivery Year but later becomes entitled to receive a State Subsidy for that Delivery Year, and the Capacity Market Seller subsequently elects to accept a State Subsidy for any part of that Delivery Year, then the Capacity Market Seller of that Capacity Resource may not receive RPM revenues for any part of that Delivery Year, unless it can demonstrate that it would have cleared in the relevant RPM Auction under an offer consistent with the resource-specific exception process outlined above in subsection 5.14(h)(3). All Capacity Market Sellers of a Jointly Owned Cross-Subsidized Capacity Resource that meets the requirements of either of the two preceding subsections (B)(ii)(1) or (2) may not receive RPM revenues for any part of that Delivery Year if any joint Capacity Market Seller of the underlying facility accepts a subsidy for that Delivery Year, unless the Capacity Market Seller can demonstrate that the facility would have cleared in the relevant RPM Auction under an offer consistent with the resource-specific exception process outlined above in subsection 5.14(h)(3). A Capacity Resource with State Subsidy that is the subject of a bilateral transaction may not receive RPM revenues for any part of that Delivery Year if any owner or Capacity Market Seller of the underlying facility receives a State Subsidy for that Delivery Year, unless the Capacity Market Seller can demonstrate that the facility would have cleared in the relevant RPM Auction under an offer consistent with the resource-specific exception process outlined above in subsection 5.14(h)(3), if any owner or Capacity Market Seller of the facility receives a State Subsidy. The Capacity Market Seller(s) of any such Capacity Resources or Jointly Owned Cross-Subsidized Capacity Resource shall return to the Office of the Interconnection any revenues paid to such Capacity Resource associated with their capacity commitment for such Delivery Year and shall retain their RPM commitment and associated obligations for the relevant Delivery Year and remain eligible to collect Performance Payments or to pay Non-Performance Charges, as applicable, pursuant to Tariff, Attachment DD, section 10A.

(iii) Any revenues returned to the Office of the Interconnection pursuant to the preceding subsections (i) and (ii) shall be allocated to the relevant load that paid for the State Subsidy (to the extent possible). If the Office of Interconnection cannot identify the relevant load responsible for the State Subsidy, then the returned revenues would be allocated across all load in the RTO that has not selected the FRR Alternative. Such revenues shall be distributed on a pro-rata basis to such LSEs that were charged a Locational Reliability Charge based on their Daily Unforced Capacity Obligations.

(5) Self-Supply Entity exemption. A Capacity Resource that is owned, or bilaterally contracted, by a Self-Supply Entity on or before December 19, 2019, shall be exempt from the Minimum Offer Price Rule if such Capacity Resource satisfies at least one of the criteria specified below:

(A) has successfully cleared an RPM Auction prior to December 19, 2019;

(B) is the subject of an interconnection construction service agreement, interim interconnection service agreement, interconnection service agreement or equivalent agreement executed on or before December 19, 2019; or

(C) is the subject of an unexecuted interconnection construction service agreement, interim interconnection service agreement, interconnection service agreement or equivalent agreement filed by PJM with the Commission on or before December 19, 2019.

(6) Intermittent Resource Exemption. A Capacity Resource with State Subsidy that is an Intermittent Resource shall be exempt from the Minimum Offer Price Rule if such Capacity Resource (1) receives or is entitled to receive State Subsidies through renewable energy credits or equivalent credits associated with a state-mandated or state-sponsored renewable portfolio standard ("RPS") program or equivalent program and (2) satisfies at least one of the following criteria:

(A) has successfully cleared an RPM Auction prior to December 19, 2019;

(B) is the subject of an interconnection construction service agreement, interim interconnection service agreement, interconnection service agreement or equivalent executed on or before December 19, 2019; or

(C) is the subject of an unexecuted interconnection construction service agreement, interim interconnection service agreement, interconnection service agreement or equivalent filed by PJM with the Commission on or before December 19, 2019.

(7) Demand Resource and Energy Efficiency Resource Exemption. A Capacity Resource with State Subsidy that is Demand Resource or an Energy Efficiency Resource shall be exempt from the Minimum Offer Price Rule if such Capacity Resource satisfies at least one of the following criteria:

(A) has successfully cleared an RPM Auction prior to December 19, 2019. For purposes of this subsection (a), individual customer location registrations (or for utility-based residential load curtailment program, based on the total number of participating customers) that participated as Demand Resource and cleared in an RPM Auction prior to December 19, 2019, and were submitted to PJM no later than 45 days prior to the BRA for the 2022/2023 Delivery Year shall be deemed eligible for the Demand Resource and Energy Efficiency Resource Exemption; or

(B) has completed registration on or before December 19, 2019; or

(C) is supported by a post-installation measurement and verification report for Energy Efficiency Resources approved by PJM on or before December 19, 2019 (calculated for each installation period, Zone and Sub-Zone by using the greater of the latest approved post-installation measurement and verification report prior to December 19, 2019 or the maximum MW cleared for a Delivery Year across all auctions conducted prior to December 19, 2019).

(8) Capacity Storage Resource Exemption. A Capacity Resource with State Subsidy that is a Capacity Storage Resource shall be exempt from the Minimum Offer Price Rule if such Capacity Storage Resource satisfies at least one of the following criteria:

(A) has successfully cleared an RPM Auction prior to December 19, 2019;

(B) is the subject of an interconnection construction service agreement, interim interconnection service agreement, interconnection service agreement or equivalent executed on or before December 19, 2019; or

(C) is the subject of an unexecuted interconnection construction service agreement, interim interconnection service agreement, interconnection service agreement or equivalent filed by PJM with the Commission on or before December 19, 2019.

(9) Procedures and Remedies in Cases of Suspected Fraud or Material Misrepresentation or Omissions in Connection with a Capacity Resource with State 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 a Capacity Resource with a State Subsidy (including whether the Capacity Resource is a Jointly Owned Cross-Subsidized Capacity Resource) or does not qualify for a competitive exemption or contains information that is inconsistent with the resource-specific exception, then:

(A) A Capacity Market Seller shall, within five (5) business days upon receipt of the request for additional information, 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 State Subsidy or whether the Capacity Market Seller is eligible for the competitive exemption. If the Office of the Interconnection determines that the Capacity Resource's status as a Capacity Resource with State Subsidy is different from that specified by the Capacity Market Seller or is not eligible for a competitive exemption pursuant to subsection (4) above, the Office of the Interconnection shall notify, in writing, the Capacity Market Seller of such determination by no later than sixty-five (65) 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, if the Office of Interconnection determines that the subject resource is a Capacity Resource with State Subsidy or is not eligible for a competitive exemption pursuant to subsection (4) above, such Capacity Resource shall be subject to the Minimum Offer Price Rule, unless and until ordered to do otherwise by FERC.

(B) if the Office of the Interconnection does not provide written notice of suspected fraudulent or material misrepresentation or omission at least sixty-five (65) 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. In such event, if the Office of Interconnection determines that a resource is a Capacity Resource with State Subsidy that is subject to the Minimum Offer Price Rule, the Office of the Interconnection will proceed with administration of the Tariff and market rules on that basis unless and until ordered to do otherwise by FERC. The Office of the Interconnection shall implement any remedies ordered by FERC; and

(C) prior to applying the Minimum Offer Price Rule, 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 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.

i) Capacity Export Charges and Credits

(1) Charge

Each Capacity Export Transmission Customer shall incur for each day of each Delivery Year a Capacity Export Charge equal to the Reserved Capacity of Long-Term Firm Transmission Service used for such export ("Export Reserved Capacity") multiplied by (the Final Zonal Capacity Price for such Delivery Year for the Zone encompassing the interface with the Control Area to which such capacity is exported minus the Final Zonal Capacity Price for such Delivery Year for the Zone in which the resources designated for export are located, but not less than zero). If more than one Zone forms the interface with such Control Area, then the amount of Reserved Capacity described above shall be apportioned among such Zones for purposes of the above calculation in proportion to the flows from such resource through each such Zone directly to such interface under CETO/CETL analysis conditions, as determined by the Office of the Interconnection using procedures set forth in the PJM Manuals. The amount of the Reserved Capacity that is associated with a fully controllable facility that crosses such interface shall be completely apportioned to the Zone within which such facility terminates.

(2) Credit

To recognize the value of firm Transmission Service held by any such Capacity Export Transmission Customer, such customer assessed a charge under section 5.14(i)(1) also shall receive a credit, comparable to the Capacity Transfer Rights provided to Load-Serving Entities under section 5.15. Such credit shall be equal to the locational capacity price difference specified in section 5.14(i)(1) times the Export Customer's Allocated Share determined as follows:

Export Customer's Allocated Share equals

(Export Path Import * Export Reserved Capacity) /

(Export Reserved Capacity + Daily Unforced Capacity Obligations of all LSEs in such Zone).

Where:

"Export Path Import" means the megawatts of Unforced Capacity imported into the export interface Zone from the Zone in which the resource designated for export is located.

If more than one Zone forms the interface with such Control Area, then the amount of Export Reserved Capacity shall be apportioned among such Zones for purposes of the above calculation in the same manner as set forth in subsection (i)(1) above.

(3) Distribution of Revenues

Any revenues collected from the Capacity Export Charge with respect to any capacity export for a Delivery Year, less the credit provided in subsection (i)(2) for such Delivery Year, shall be distributed to the Load Serving Entities in the export-interface Zone that were assessed a

Locational Reliability Charge for such Delivery Year, pro rata based on the Daily Unforced Capacity Obligations of such Load-serving Entities in such Zone during such Delivery Year. If more than one Zone forms the interface with such Control Area, then the revenues shall be apportioned among such Zones for purposes of the above calculation in the same manner as set forth in subsection (i)(1) above.

5.14A [Reserved.]

5.14B Generating Unit Capability Verification Test Requirements Transition Provision for RPM Delivery Years 2014/2015, 2015/2016, and 2016/2017

A. This transition provision applies only with respect to Generation Capacity Resources with existing capacity commitments for the 2014/2015, 2015/2016, or 2016/2017 Delivery Years that experience reductions in verified installed capacity available for sale as a direct result of revised generating unit capability verification test procedures effective with the summer 2014 capability tests, as set forth in the PJM Manuals. A Generation Capacity Resource meeting the description of the preceding sentence, and the Capacity Market Seller of such a resource, are hereafter in this section 5.14B referred to as an "Affected Resource" and an "Affected Resource Owner," respectively.

B. For each of its Affected Resources, an Affected Resource Owner is required to provide documentation to the Office of the Interconnection sufficient to show a reduction in installed capacity value as a direct result of the revised capability test procedures. Upon acceptance by the Office of the Interconnection, the Affected Resource's installed capacity value will be updated in the eRPM system to reflect the reduction, and the Affected Resource's Capacity

Interconnection Rights value will be updated to reflect the reduction, effective June 1, 2014. The reduction's impact on the Affected Resource's existing capacity commitments for the 2014/2015 Delivery Year will be determined in Unforced Capacity terms, using the final EFORd value established by the Office of the Interconnection for the 2014/2015 Delivery Year as applied to the Third Incremental Auction for the 2014/2015 Delivery Year, to convert installed capacity to Unforced Capacity. The reduction's impact on the Affected Resource's existing capacity commitments for each of the 2015/2016 and 2016/2017 Delivery Years will be determined in Unforced Capacity terms, using the EFORd value from each Sell Offer in each applicable RPM Auction, applied on a pro-rata basis, to convert installed capacity to Unforced Capacity. The Unforced Capacity impact for each Delivery Year represents the Affected Resource's capacity commitment shortfall, resulting wholly and directly from the revised capability test procedures, for which the Affected Resource Owner is subject to a Capacity Resource Deficiency Charge for the Delivery Year, as described in section 8 of this Attachment DD, unless the Affected Resource Owner (i) provides replacement Unforced Capacity, as described in section 8.1 of this Attachment DD, prior to the start of the Delivery Year to resolve the Affected Resource's total capacity commitment shortfall; or (ii) requests relief from Capacity Resource Deficiency Charges that result wholly and directly from the revised capability test procedures by electing the transition mechanism described in this section 5.14B ("Transition Mechanism").

C. Under the Transition Mechanism, an Affected Resource Owner may elect to have the Unforced Capacity commitments for all of its Affected Resources reduced for the 2014/2015, 2015/2016, or 2016/2017 Delivery Years to eliminate the capacity commitment shortfalls, across all of its Affected Resources, that result wholly and directly from the revised capability test procedures, and for which the Affected Resource Owner otherwise would be subject to Capacity Resource Deficiency Charges for the Delivery Year. In electing this option, the Affected Resource Owner relinquishes RPM Auction Credits associated with the reductions in Unforced Capacity commitments for all of its Affected Resources for the Delivery Year, and Locational Reliability Charges as described in section 5.14(e) of this Attachment DD are adjusted accordingly. Affected Resource Owners wishing to elect the Transition Mechanism for the 2015/2016 Delivery Year must notify the Office of the Interconnection by May 30, 2014. Affected Resource Owners wishing to elect the Transition Mechanism for the 2016/2017 Delivery Year must notify the Office of the Interconnection by July 25, 2014.

D. The Office of the Interconnection will offset the total reduction (across all Affected Resources and Affected Resource Owners) in Unforced Capacity commitments associated with the Transition Mechanism for the 2015/2016 and 2016/2017 Delivery Years by applying corresponding adjustments to the quantity of Buy Bid or Sell Offer activity in the upcoming Incremental Auctions for each of those Delivery Years, as described in sections 5.12(b)(ii) and 5.12(b)(iii) of this Attachment DD.

E. By electing the Transition Mechanism, an Affected Resource Owner may receive relief from applicable Capacity Resource Deficiency Charges for the 2014/2015, 2015/2016, or 2016/2017 Delivery Years, and a Locational UCAP Seller that sells Locational UCAP based on an Affected Resource owned by the Affected Resource Owner may receive relief from applicable Capacity Resource Deficiency Charges for the 2014/2015 Delivery Year, to the extent that the Affected Resource Owner demonstrates, to the satisfaction of the Office of the Interconnection, that an inability to deliver the amount of Unforced Capacity previously committed for the 2014/2015, 2015/2016, or 2016/2017 Delivery Years is due to a reduction in verified installed capacity available for sale as a direct result of revised generating unit capability verification test procedures effective with the summer 2014 capability tests, as set forth in the PJM Manuals; provided, however, that the Affected Resource Owner must provide the Office of the Interconnection with all information deemed necessary by the Office of the Interconnection to assess the merits of the request for relief.

5.14C Demand Response Operational Resource Flexibility Transition Provision for RPM Delivery Years 2015/2016 and 2016/2017

A. This transition provision applies only to Demand Resources for which a Curtailment Service Provider has existing RPM commitments for the 2015/2016 or 2016/2017 Delivery Years (alternatively referred to in this section 5.14C as "Applicable Delivery Years" and each an "Applicable Delivery Year") that (i) cannot satisfy the 30-minute notification requirement as described in Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA; (ii) are not excepted from the 30-minute notification requirement as described in Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA; and (iii) cleared in the Base Residual Auction or First Incremental Auction for the 2015/2016 Delivery Year, or cleared in the Base Residual Auction for the 2016/2017 Delivery Year. A Demand Resource meeting these criteria and the Curtailment Service Provider of such a resource are hereafter in this section 5.14C referred to as an "Affected Demand Resource" and an "Affected Curtailment Service Provider," respectively.

B. For this section 5.14C to apply to an Affected Demand Resource, the Affected Curtailment Service Provider must notify the Office of the Interconnection in writing, with regard to the following information by the applicable deadline:

i) For each applicable Affected Demand Resource: the number of cleared megawatts of Unforced Capacity for the Applicable Delivery Year by end-use customer site that the Affected Curtailment Service Provider cannot deliver, calculated based on the most current information available to the Affected Curtailment Service Provider; the end-use customer name; electric distribution company's account number for the end-use customer; address of end-use customer; type of Demand Resource (i.e., Limited DR, Annual DR, Extended Summer DR); the Zone or sub-Zone in which the end-use customer is located; and, a detailed description of why the end-use customer cannot comply with the 30-minute notification requirement or qualify for one of the exceptions to the 30-minute notification requirement provided in Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA.

ii) If applicable, a detailed analysis that quantifies the amount of cleared megawatts of Unforced Capacity for the Applicable Delivery Year for prospective customer sales that could not be contracted by the Affected Curtailment Service Provider because of the 30-minute notification requirement provided in Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA that the Affected Curtailment Service Provider cannot deliver, by type of Demand Resource (i.e. Limited DR, Annual DR, Extended Summer DR) and by Zone and sub-Zone, as applicable. The analysis should include the amount of Unforced Capacity expected from prospective customer sales for each Applicable Delivery Year and must include supporting detail to substantiate the difference in reduced sales expectations. The Affected Curtailment Service Provider should maintain records to support its analysis.

1. For the 2015/2016 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the Third Incremental Auction for the 2015/2016 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision may not sell or offer to sell megawatts in the modeled LDA or sub-LDA where an Affected Demand Resource is located in the Third Incremental Auction for the 2015/2016 Delivery Year.

2. For the 2016/2017 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the Second Incremental Auction for the 2016/2017 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision may not sell or offer to sell megawatts in the modeled LDA or sub-LDA where an Affected Demand Resource is located in the Second or Third Incremental Auctions for the 2016/2017 Delivery Year.

3. For the 2016/2017 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the Third Incremental Auction for the 2016/2017 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision must not have sold or offered to sell megawatts in the modeled LDA or sub-LDA where an Affected Demand Resource is located in the Second Incremental Auction for the 2016/2017 Delivery Year, and may not sell or offer to sell megawatts in the modeled LDA or sub-LDA where an Affected Demand Resource is located in the Third Incremental Auction for the 2016/2017 Delivery Year.

C. For the Third Incremental Auction for the 2015/2016 Delivery Year and the First, Second, and Third Incremental Auctions for the 2016/2017 Delivery Year, the Office of the Interconnection shall publish aggregate information on the undeliverable megawatts declared under this transition provision (hereafter, "non-viable megawatts"), by type of Demand Resource and by Zone or sub-Zone, concurrently with its posting of planning parameters for the applicable Scheduled Incremental Auction. Non-viable megawatts for a Scheduled Incremental Auction for an Applicable Delivery Year represent those megawatts meeting the criteria of subsection A above and declared in accordance with subsection B above. Prior to each Third Incremental Auction for an Applicable Delivery Year, the Office of the Interconnection shall apply adjustments equal to the declared non-viable megawatt quantity to the quantity of Buy Bid or Sell Offer activity in the upcoming Scheduled Incremental Auctions for the Applicable Delivery Year, as described in sections 5.12(b)(ii) and 5.12(b)(iii) of this Attachment DD. Prior to the Second Incremental Auction for the 2016/2017 Delivery Year, the Office of the Interconnection shall adjust the recalculated PJM Region Reliability Requirement and recalculated LDA Reliability Requirements, as described in section 5.4(c) of this Attachment DD, by the applicable quantity of declared non-viable megawatts, and shall update the PJM Region Reliability Requirement and each LDA Reliability Requirement for such Second Incremental Auction only if the combined change of the applicable adjustment and applicable recalculation is greater than or equal to the lessor of (i) 500 megawatts or (ii) one percent of the prior PJM Region Reliability

Requirement or one percent of the prior LDA Reliability Requirement, as applicable.

D. Prior to the start of each Applicable Delivery Year, the Office of the Interconnection shall reduce, by type of Demand Resource and by Zone or sub-Zone, the capacity commitment of each Affected Curtailment Service Provider that utilizes this transition provision for the Applicable Delivery Year based on the non-viable megawatts declared by the Affected Curtailment Service Provider under this transition provision. If the Affected Curtailment Service Provider cleared megawatts from multiple Affected Demand Resources of the same type and Zone or sub-Zone, or cleared megawatts in multiple RPM Auctions for the Applicable Delivery Year, the Office of the Interconnection shall allocate the reduction in capacity commitment by type of Demand Resource and by Zone or sub-Zone across the applicable Affected Demand Resources and relevant RPM Auctions. Such allocation shall be performed on a pro-rata basis, based on megawatts cleared by the Affected Demand Resources in the relevant RPM Auctions.

E. For each Applicable Delivery Year, an Affected Curtailment Service Provider that utilizes this transition provision for the Applicable Delivery Year relinquishes an Affected Demand Resource's RPM Auction Credits for the amount of capacity commitment reduction as determined under subsection D above. Locational Reliability Charges as described in section 5.14(e) of this Attachment DD are also adjusted accordingly.

5.14D Capacity Performance and Base Capacity Transition Provision for RPM Delivery Years 2016/2017 and 2017/2018

A. This transition provision applies only for procuring Capacity Performance Resources for the 2016/2017 and 2017/2018 Delivery Years.

B. For both the 2016/2017 and 2017/2018 Delivery Years, PJM will hold a Capacity Performance Transition Incremental Auction to procure Capacity Performance Resources.

1. For each Capacity Performance Transition Incremental Auction, the optimization algorithm shall consider:

- the target quantities of Capacity Performance Resources specified below;
- the Sell Offers submitted in such auction.

The Office of the Interconnection shall submit a Buy Bid based on the quantity of Capacity Performance Resources specified for that Delivery Year. For the 2016/2017 Delivery Year, the Office of the Interconnection shall submit a Buy Bid, at a price no higher than 0.5 times the Net CONE value for the PJM Region determined for the Base Residual Auction for that Delivery Year, for a quantity of Capacity Performance Resources equal to 60 percent of the updated Reliability Requirement for the PJM Region. For the 2017/2018 Delivery Year, the Office of the Interconnection shall submit a Buy Bid, at a price no higher than 0.6 times the Net CONE value for the PJM Region determined for the Base Residual Auction for that Delivery Year, for a quantity of Capacity Performance Resources equal to 70 percent of the updated Reliability Requirement for the PJM Region.

2. For each Capacity Performance Transition 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. For the 2016/2017 Delivery Year, the Capacity Resource Clearing Price for any Capacity Performance Transition Incremental Auction shall not exceed 0.5 times the Net CONE value for the PJM Region determined for the Base Residual Auction for that Delivery Year. For the 2017/2018 Delivery Year, the Capacity Resource Clearing Price for any Capacity Performance Transition Incremental Auction shall not exceed 0.6 times the Net CONE value for the PJM Region determined for the Base Residual Auction for that Delivery Year.

3. A Capacity Market Seller may offer any Capacity Resource that has not been committed in an FRR Capacity Plan, that qualifies as a Capacity Performance Resource under section 5.5A(a) and that (i) has not cleared an RPM Auction for that Delivery Year; or (ii) has cleared in an RPM Auction for that Delivery Year. A Capacity Market Seller may offer an external Generation Capacity Resource to the extent that such resource: (i) is reasonably expected, by the relevant Delivery Year, to meet all applicable requirements to be treated as equivalent to PJM Region internal generation that is not subject to NERC tagging as an interchange transaction; (ii) has long-term firm transmission service confirmed on the complete transmission path from such resource into PJM; and (iii) is, by written commitment of the Capacity Market Seller, subject to the same obligations imposed on Generation Capacity Resources located in the PJM Region by section 6.6 of Attachment DD of the PJM Tariff to offer their capacity into RPM Auctions.

4. Capacity Resources that already cleared an RPM Auction for a Delivery Year, retain the capacity obligations for that Delivery Year, and clear in a Capacity Performance Transition Incremental Auction for the same Delivery Year shall: (i) receive a payment equal to the Capacity Resource Clearing Price as established in that Capacity Performance Transition Incremental Auction; and (ii) not be eligible to receive a payment for clearing in any prior RPM Auction for that Delivery Year.

D. All Capacity Performance Resources that clear in a Capacity Performance Transition Incremental Auction will be subject to the Non-Performance Charge set forth in section 10A.

5.14E Demand Response Legacy Direct Load Control Transition Provision for RPM Delivery Years 2016/2017, 2017/2018, and 2018/2019

A. This transition provision applies only to Demand Resources for which a Curtailment Service Provider has existing RPM commitments for the 2016/2017, 2017/2018, or 2018/2019 Delivery Years (alternatively referred to in this section 5.14E as "Applicable Delivery Years" and each an "Applicable Delivery Year") that (i) qualified as Legacy Direct Load Control before June 1, 2016 as described in Section G of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA; (ii) cannot meet the requirements for using statistical sampling for residential non-interval metered customers as described in Section K of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA; and (iii) cleared in the Base Residual Auction or First Incremental Auction for the 2016/2017 Delivery Year, cleared in the Base Residual Auction for the 2017/2018 Delivery Year, or cleared in the Base Residual Auction for the 2018/2019 Delivery Year. A Demand Resource meeting these criteria and the

Curtailment Service Provider of such a resource are hereafter in this section 5.14E referred to as an “Affected Demand Resource” and an “Affected Curtailment Service Provider,” respectively.

B. For this section 5.14E to apply to an Affected Demand Resource, the Affected Curtailment Service Provider must notify the Office of the Interconnection in writing, with regard to the following information, by the applicable deadline:

i) For each applicable Affected Demand Resource: the number of cleared megawatts of Unforced Capacity for the Applicable Delivery Year by end-use customer site that the Affected Curtailment Service Provider cannot deliver, calculated based on the most current information available to the Affected Curtailment Service Provider; electric distribution company’s account number for the end-use customer; address of end-use customer; type of Demand Resource (i.e., Limited DR, Annual DR, Extended Summer DR); the Zone or sub-Zone in which the end-use customer is located; and, a detailed description of why the endues customer cannot comply with statistical sampling for residential non-interval metered customers requirement as described in Section K of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA.

ii) If applicable, a detailed analysis that quantifies the amount of cleared megawatts of Unforced Capacity for the Applicable Delivery Year for prospective customer sales that could not be contracted by the Affected Curtailment Service Provider because of the statistical sampling for residential non-interval metered customers requirement as described in Section K of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA that the Affected Curtailment Service Provider cannot deliver, by type of Demand Resource (i.e. Limited DR, Annual DR, Extended Summer DR) and by Zone and sub-Zone, as applicable. The analysis should include the amount of Unforced Capacity expected from prospective customer sales for each Applicable Delivery Year and must include supporting detail to substantiate the difference in reduced sales expectations. The Affected Curtailment Service Provider should maintain records to support its analysis.

1. For the 2016/2017 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the Second and/or Third Incremental Auction for the 2016/2017 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision may not sell or offer to sell megawatts in the matching LDA or sub-LDA where an Affected Demand Resource is located in the Second or Third Incremental Auction for the 2016/2017 Delivery Year.

2. For the 2017/2018 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the First, Second and/or Third Incremental Auction for the 2017/2018 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision may not sell or offer to sell megawatts in the matching LDA or sub-LDA where an Affected Demand Resource is located in the First, Second or Third Incremental Auctions for the 2017/2018 Delivery Year.

3. For the 2018/2019 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the First, Second and/or Third Incremental Auction for the 2018/2019 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision may not sell or offer to sell megawatts in the matching LDA or sub-LDA where an Affected Demand Resource is located in the First, Second or Third Incremental Auctions for the 2018/2019 Delivery Year.

C. For the Second and Third Incremental Auction for the 2016/2017 Delivery Year, the First, Second, and Third Incremental Auctions for the 2017/2018 Delivery Year, and the First, Second, and Third Incremental Auctions for the 2018/2019 Delivery Year, the Office of the Interconnection shall publish aggregate information on the undeliverable megawatts declared under this transition provision (hereafter, "non-viable megawatts"), by type of Demand Resource and by Zone or sub-Zone, concurrently with its posting of planning parameters for the applicable Scheduled Incremental Auction. Non-viable megawatts for a Scheduled Incremental Auction for an Applicable Delivery Year represent those megawatts meeting the criteria of subsection A above and declared in accordance with subsection B above. Prior to each Scheduled Incremental Auction for an Applicable Delivery Year, the Office of the Interconnection shall apply adjustments equal to the declared non-viable megawatt quantity to the quantity of Buy Bid or Sell Offer activity in the upcoming Scheduled Incremental Auctions for the Applicable Delivery Year, as described in sections 5.12(b)(ii) and 5.12(b)(iii) of this Attachment DD. Prior to the Second Incremental Auction for the 2016/2017 Delivery Year, the First and Second Incremental Auction for the 2017/2018 Delivery Year, and the First and Second Incremental Auction for the 2018/2019 Delivery Year, the Office of the Interconnection shall adjust the recalculated PJM Region Reliability Requirement and recalculated LDA Reliability Requirements, as described in section 5.4(c) of this Attachment DD, by the applicable quantity of declared non-viable megawatts, and shall update the PJM Region Reliability Requirement and each LDA Reliability Requirement for such Incremental Auction only if the combined change of the applicable adjustment and applicable recalculation is greater than or equal to the lessor of (i) 500 megawatts or (ii) one percent of the prior PJM Region Reliability Requirement or one percent of the prior LDA Reliability Requirement, as applicable.

D. Prior to the start of each Applicable Delivery Year, the Office of the Interconnection shall reduce, by type of Demand Resource and by Zone or sub-Zone, the capacity commitment of each Affected Curtailment Service Provider that utilizes this transition provision for the Applicable Delivery Year based on the non-viable megawatts declared by the Affected Curtailment Service Provider under this transition provision. If the Affected Curtailment Service Provider cleared megawatts from multiple Affected Demand Resources of the same type and Zone or sub-Zone, or cleared MWs in multiple RPM Auctions for the Applicable Delivery Year, the Office of the Interconnection shall allocate the reduction in capacity commitment by type of Demand Resource and by Zone or sub-Zone across the applicable Affected Demand Resources and relevant RPM Auctions. Such allocation shall be performed on a pro-rata basis, based on megawatts cleared by the Affected Demand Resources in the relevant RPM Auctions.

E. For each Applicable Delivery Year, an Affected Curtailment Service Provider that utilizes this transition provision for the Applicable Delivery Year relinquishes an Affected Demand Resource's RPM Auction credits for the amount of capacity commitment reduction as determined under subsection D above. Locational Reliability Charges as described in section 5.14(e) of this Attachment DD are also adjusted accordingly.

6. MARKET POWER MITIGATION

6.1 Applicability

The provisions of the Market Monitoring Plan (in Tariff, Attachment M and Attachment - M Appendix and this section 6) shall apply to the Reliability Pricing Model Auctions.

6.2 Process

(a) [Reserved for Future Use]

(b) In accordance with the schedule specified in the PJM Manuals, following PJM's conduct of a Base Residual Auction or Incremental Auction pursuant to Tariff, Attachment DD, section 5.12, but prior to the Office of the Interconnection's final determination of clearing prices and charges pursuant to Tariff, Attachment DD, section 5.14, the Office of the Interconnection shall: (i) apply the Market Structure Test to any LDA having a Locational Price Adder greater than zero and to the entire PJM region; (ii) apply Market Seller Offer Caps, if required under this section 6; and (iii) recompute the optimization algorithm to clear the auction with the Market Seller Offer Caps in place.

(c) Within seven days after the deadline for submission of Sell Offers in a Base Residual Auction or Incremental Auction, the Office of the Interconnection shall file with FERC a report of any determination made pursuant to Tariff, Attachment DD, section 5.14(h), Tariff, Attachment DD, section 6.5(a)(ii), or Tariff, Attachment DD, section 6.7(c) identified in such sections as subject to the procedures of this section. Such report shall list each such determination, the information considered in making each such determination, and an explanation of each such determination. Any entity that objects to any such determination may file a written objection with FERC no later than seven days after the filing of the report. Any such objection must not merely allege that the determination was in error, and must provide support for the objection, demonstrating that the determination overlooked or failed to consider relevant evidence. In the event that no objection is filed, the determination shall be final. In the event that an objection is filed, FERC shall issue any decision modifying the determination no later than 60 days after the filing of such report; otherwise, the determination shall be final. Final auction results shall reflect any decision made by FERC regarding the report.

6.3 Market Structure Test

(a) [Reserved for Future Use]

(b) Market Structure Test.

A constrained LDA or the PJM Region shall fail the Market Structure Test, and mitigation shall be applied to all jointly pivotal suppliers (including all Affiliates of such suppliers, and all third-party supply in the relevant LDA controlled by such suppliers by contract), if, as to the Sell Offers that comprise the incremental supply determined pursuant to section 6.3(c) below that are based on Generation Capacity Resources, there are not more than three jointly pivotal suppliers. The Office of the Interconnection shall apply the Market Structure Test. The Office of the Interconnection shall confirm the results of the Market Structure Test with the Market Monitoring Unit.

(c) Determination of Incremental Supply

In applying the Market Structure Test, the Office of the Interconnection shall consider all (i) incremental supply (provided, however, that the Office of the Interconnection shall consider only such supply available from Generation Capacity Resources) available to solve the constraint applicable to a constrained LDA offered at less than or equal to 150% of the cost-based clearing price; or (ii) supply for the PJM Region, offered at less than or equal to 150% of the cost-based clearing price, provided that supply in this section includes only the lower of cost-based or market-based offers from Generation Capacity Resources. Cost-based clearing prices are the prices resulting from the RPM auction algorithm using the lower of cost-based or price-based offers for all Capacity Resources.

6.4 Market Seller Offer Caps

(a) The Market Seller Offer Cap, stated in dollars per MW/day of unforced capacity, applicable to price-quantity offers within the Base Offer Segment for an Existing Generation Capacity Resource shall be the Avoidable Cost Rate for such resource, less the Projected PJM Market Revenues for such resource, stated in dollars per MW/day of unforced capacity, provided, however, that the default Market Seller Offer Cap for any Capacity Performance Resource shall be the product of (the Net Cost of New Entry applicable for the Delivery Year and Locational Deliverability Area for which such Capacity Performance Resource is offered times the average of the Balancing Ratios in the three consecutive calendar years (during the Performance Assessment Intervals in such calendar years) that precede the Base Residual Auction for such Delivery Year), however, for the Base Residual Auction for the 2021/2022 Delivery Year, the Balancing Ratio used in the determination of the default Market Seller Offer Cap shall be 78.5 percent, and provided further that the submission of a Sell Offer with an Offer Price at or below the revised Market Seller Offer Cap permitted under this proviso shall not, in and of itself, be deemed an exercise of market power in the RPM market; nor shall a Sell Offer with an Offer Price equal to the applicable MOPR Floor Offer Price, in and of itself, be deemed an exercise of market power in the RPM market. Notwithstanding the previous sentence, a Capacity Market Seller may seek and obtain a Market Seller Offer Cap for a Capacity Performance Resource that exceeds the revised Market Seller Offer Cap permitted under the prior sentence, if it supports and obtains approval of such alternative offer cap pursuant to the procedures and standards of subsection (b) of this section 6.4. A Capacity Market Seller may not use the Capacity Performance default Market Seller Offer Cap, and also seek to include any one or more categories of the Avoidable Cost Rate defined in Tariff, Attachment DD, section 6.8 below. The Market Seller Offer Cap for an Existing Generation Capacity Resource shall be the Opportunity Cost for such resource, if applicable, as determined in accordance with Tariff, Attachment DD, section 6.7. Nothing herein shall preclude any Capacity Market Seller and the Market Monitoring Unit from agreeing to, nor require either such entity to agree to, an alternative market seller offer cap determined on a mutually agreeable basis. Any such alternative offer cap shall be filed with the Commission for its approval. This provision is duplicated in Tariff, Attachment M-Appendix, section II.E.3.

(b) For each Existing Generation Capacity Resource, a potential Capacity Market Seller must provide to the Market Monitoring Unit and the Office of the Interconnection data and documentation required under section 6.7 below to establish the level of the Market Seller Offer Cap applicable to each resource by no later than one hundred twenty (120) days prior to the commencement of the offer period for the applicable RPM Auction. The Capacity Market Seller must promptly address any concerns identified by the Market Monitoring Unit regarding the data and documentation provided, review the Market Seller Offer Cap proposed by the Market Monitoring Unit, and attempt to reach agreement with the Market Monitoring Unit on the level of the Market Seller Offer Cap by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction. The Capacity Market Seller shall notify the Market Monitoring Unit in writing, with a copy to the Office of the Interconnection, whether an agreement with the Market Monitoring Unit has been reached or, if no agreement has been reached, specifying the level of Market Seller Offer Cap to which it commits by no later than eighty (80) days prior to the commencement of the offer period for the applicable RPM Auction. The Office of the Interconnection shall review the data submitted by the Capacity Market Seller, make a determination whether to accept or reject the requested unit-specific Market Seller Offer Cap, and notify the Capacity Market Seller and the Market Monitoring Unit of its determination in writing, by no later than sixty-five (65) days prior to the commencement of the offer period for the applicable RPM Auction. If the Market Monitoring Unit does not provide its determination to the Capacity Market Seller and the Office of the Interconnection by the specified deadline, by no later than sixty-five (65) days prior to the commencement of the offer period for the applicable RPM Auction the Office of the Interconnection will make the determination of the level of the Market Seller Offer Cap, which shall be deemed to be final. If the Capacity Market Seller does not notify the Market Monitoring Unit and the Office of the Interconnection of the Market Seller Offer Cap it desires to utilize by no later than eighty (80) days prior to the commencement of the offer period for the applicable RPM Auction, it shall be required to utilize a Market Seller Offer Cap determined using the applicable default Avoidable Cost Rate specified in section 6.7(c) below.

(c) Nothing in this section precludes the Capacity Market Seller from filing a petition with FERC seeking a determination of whether the Sell Offer complies with the requirements of the Tariff.

(d) For any Third Incremental Auction for Delivery Years through the 2017/2018 Delivery Year, the Market Seller Offer Cap for an Existing Generation Capacity Resource shall be determined pursuant to subsection (a) of this Section 6.4, or if elected by the Capacity Market Seller, shall be equal to 1.1 times the Capacity Resource Clearing Price in the Base Residual Auction for the relevant LDA and Delivery Year. For any Third Incremental Auction for the 2018/2019 or 2019/2020 Delivery Years, the Market Seller Offer Cap for an Existing Generation Capacity Resource offering as a Base Capacity resource shall be determined pursuant to subsection (a) of this Section 6.4, or if elected by the Capacity Market Seller, shall be equal to 1.1 times the Capacity Resource Clearing Price in the Base Residual Auction for the relevant LDA and Delivery Year. For any Third Incremental Auction for the 2018/2019 Delivery Year or any subsequent Delivery Year, the Market Seller Offer Cap for an Existing Generation Capacity Resource offering as a Capacity Performance Resource shall be determined pursuant to subsection (a) of this Section 6.4, or if elected by the Capacity Market Seller, shall be equal to the greater of the Net Cost of New Entry times the Balancing Ratio for the relevant LDA and Delivery Year or 1.1 times the

Capacity Resource Clearing Price in the Base Residual Auction for the relevant LDA and Delivery Year.

6.5 Mitigation

The Office of the Interconnection shall apply market power mitigation measures in any Base Residual Auction or Incremental Auction for any LDA, Unconstrained LDA Group, or the PJM Region that fails the Market Structure Test.

(a) Mitigation for Generation Capacity Resources.

i) Existing Generation Capacity Resource

Mitigation will be applied on a unit-specific basis and only if the Sell Offer of Unforced Capacity from an Existing Generation Capacity Resource: (1) is greater than the Market Seller Offer Cap applicable to such resource; and (2) would, absent mitigation, increase the Capacity Resource Clearing Price in the relevant auction. If such conditions are met, such Sell Offer shall be set equal to the higher of the applicable Market Seller Offer Cap or the applicable MOPR Floor Offer Price.

ii) Planned Generation Capacity Resources

(A) Sell Offers based on Planned Generation Capacity Resources (including External Planned Generation Capacity Resources) shall be presumed to be competitive and shall not be subject to market power mitigation in any Base Residual Auction or Incremental Auction for which such resource qualifies as a Planned Generation Capacity Resource, but any such Sell Offer shall be rejected if it meets the criteria set forth in subsection (C) below, unless the Capacity Market Seller obtains approval from FERC for use of such offer prior to the close of the offer period for the applicable RPM Auction.

(B) Sell Offers based on Planned Generation Capacity Resources (including Planned External Generation Capacity Resources) shall be deemed competitive and not be subject to mitigation if: (1) collectively all such Sell Offers provide Unforced Capacity in an amount equal to or greater than two times the incremental quantity of new entry required to meet the LDA Reliability Requirement; and (2) at least two unaffiliated suppliers have submitted Sell Offers for Planned Generation Capacity Resources in such LDA. Notwithstanding the foregoing, any Capacity Market Seller, together with Affiliates, whose Sell Offers based on Planned Generation Capacity Resources in that modeled LDA are pivotal, shall be subject to mitigation.

(C) Where the two conditions stated in subsection (B) above are not met, or the Sell Offer is pivotal, the Sell Offer shall be rejected if it exceeds the higher of the applicable MOPR Floor Offer Price, if applicable, or 140 percent of: 1) the average of location-adjusted Sell Offers for Planned

Generation Capacity Resources from the same asset class as such Sell Offer, submitted (and not rejected) (Asset-Class New Plant Offers) for such Delivery Year; or 2) if there are no Asset-Class New Plant Offers for such Delivery Year, the average of Asset-Class New Plant Offers for all prior Delivery Years; or 3) if there are no Asset-Class New Plant Offers for any prior Delivery Year, the Net CONE applicable for such Delivery Year in the LDA for which such Sell Offer was submitted. For purposes of this section, asset classes shall be as stated in section 6.7(c) below as effective for such Delivery Year, and Asset-Class New Plant Offers shall be location-adjusted by the ratio between the Net CONE effective for such Delivery Year for the LDA in which the Sell Offer subject to this section was submitted and the average, weighted by installed capacity, of the Net CONEs for all LDAs in which the units underlying such Asset Class New Plant Offers are located. Following the conduct of the applicable auction and before the final determination of clearing prices, in accordance with Section 6.2(b) above, each Capacity Market Seller whose Sell Offer is so rejected shall be notified in writing by the Office of the Interconnection by no later than one (1) Business Day after the close of the offer period for the applicable RPM Auction and allowed an opportunity to submit a revised Sell Offer that does not exceed such threshold within one (1) Business Day of the Office of the Interconnection's rejection of such Sell Offer. If such revised Sell Offer is accepted by the Office of the Interconnection, the Office of the Interconnection then shall clear the auction with such revised Sell Offer in place. Pursuant to Tariff, Attachment M-Appendix, Section II.F, the Market Monitoring Unit shall notify in writing each Capacity Market Seller whose Sell Offer has been determined to be non-competitive and subject to mitigation, with a copy to the Office of the Interconnection, by no later than one (1) Business Day after the close of the offer period for the applicable RPM Auction.

(b) Mitigation for Demand Resources

The Market Seller Offer Cap shall not be applied to Sell Offers of Demand Resources or Energy Efficiency Resources.

6.6 Offer Requirement for Capacity Resources

(a) To avoid application of subsection (h) below, all of the installed capacity of all Existing Generation Capacity Resources located in the PJM Region shall be offered by the Capacity Market Seller that owns or controls all or part of such resource (which may include submission as Self-Supply) in all RPM Auctions for each Delivery Year, less any amount determined by the Office of the Interconnection to be eligible for an exception to this RPM must-offer requirement, where installed capacity is determined as of the date on which bidding commences for each RPM Auction pursuant to Tariff, Attachment DD, section 5.6.6. The Unforced Capacity of such resources is determined using the EFORd value that is submitted by the Capacity Market Seller in its Sell Offer, which shall not exceed the maximum EFORd for that resource as defined in section 6.6(b). If a resource should be included on the list of Existing

Generation Capacity Resources subject to the RPM must-offer requirement that is maintained by the Market Monitoring Unit pursuant to Tariff, Attachment M-Appendix, section II.C.1, but is omitted therefrom whether by mistake of the Market Monitoring Unit or failure of the Capacity Market Seller that owns or controls all or part of such resource to provide information about the resource to the Market Monitoring Unit, this shall not excuse such resource from the RPM must-offer requirement.

(b) For each Existing Generation Capacity Resource, a potential Capacity Market Seller must timely provide to the Market Monitoring Unit and the Office of the Interconnection all data and documentation required under this section 6.6 to establish the maximum EFORd applicable to each resource in accordance with standards and procedures specified in the PJM Manuals. The maximum EFORd that may be used in a Sell Offer for RPM Auctions held prior to the date on which the final EFORds used for a Delivery Year are posted, is the greater of (i) the average EFORd for the five consecutive years ending on the September 30 that last precedes the Base Residual Auction, or (ii) the EFORd for the 12 months ending on the September 30 that last precedes the Base Residual Auction.

Notwithstanding the foregoing, a Capacity Market Seller may request an alternate maximum EFORd for Sell Offers submitted in such auctions if it has a documented, known reason that would result in an increase in its EFORd, by submitting a written request to the Market Monitoring Unit and Office of the Interconnection, along with data and documentation required to support the request for an alternate maximum EFORd, by no later one hundred twenty (120) days prior to the commencement of the offer period for the Base Residual Auction for the applicable Delivery Year. The Capacity Market Seller must address any concerns identified by the Market Monitoring Unit and/or the Office of the Interconnection regarding the data and documentation provided and attempt to reach agreement with the Market Monitoring Unit on the level of the alternate maximum EFORd by no later than ninety (90) days prior to the commencement of the offer period for the Base Residual Auction for the applicable Delivery Year. As further described in Tariff, Attachment M-Appendix, section II.C, the Market Monitoring Unit shall notify the Capacity Market Seller and the Office of the Interconnection in writing of its determination of the requested alternate maximum EFORd by no later than ninety (90) days prior to the commencement of the offer period for the Base Residual Auction for the applicable Delivery Year. By no later than eighty (80) days prior to the commencement of the offer period for the Base Residual Auction for the applicable Delivery Year, the Capacity Market Seller shall notify the Office of the Interconnection and the Market Monitoring Unit in writing whether it agrees with the Market Monitoring Unit on the alternate maximum EFORd or, if no agreement has been reached, specifying the level of alternate maximum EFORd to which it commits. If a Capacity Market Seller fails to request an alternate maximum EFORd prior to the specified deadlines, the maximum EFORd for the applicable RPM Auction shall be deemed to be the default EFORd calculated pursuant to this section.

The maximum EFORd that may be used in a Sell Offer for Third Incremental Auction, and for Conditional Incremental Auctions held after the date on which the final EFORd used for a Delivery Year is posted, is the EFORd for the 12 months ending on the September 30 that last precedes the submission of such offers.

(c) [Reserved for Future Use]

(d) In the event that a Capacity Market Seller and the Market Monitoring Unit cannot agree on the maximum level of the alternate EFORd that may be used in a Sell Offer for RPM Auctions held prior to the date on which the final EFORds used for a Delivery Year are posted, the Office of the Interconnection shall make its own determination of the maximum level of the alternate EFORd based on the requirements of the Tariff and the PJM Manuals, per Tariff, Attachment DD, section 5.8, by no later than sixty-five (65) days prior to the commencement of the offer period for the Base Residual for the applicable Delivery Year, and shall notify the Capacity Market Seller and the Market Monitoring Unit in writing of such determination.

(e) Nothing in this section precludes the Capacity Market Seller from filing a petition with FERC seeking a determination of whether the EFORd complies with the requirements of the Tariff.

(f) Notwithstanding the foregoing, a Capacity Market Seller may submit an EFORd that it chooses for an RPM Auction held prior to the date on which the final EFORd used for a Delivery Year is posted, provided that (i) it has participated in good faith with the process described in this section 6.6 and in Tariff, Attachment M-Appendix, section II.C, (ii) the offer is no higher than the level defined in any agreement reached by the Capacity Market Seller and the Market Monitoring Unit that resulted from the foregoing process, and (iii) the offer is accepted by the Office of the Interconnection subject to the criteria set forth in the Tariff and the PJM Manuals.

(g) A Capacity Market Seller that owns or controls an existing generation resource in the PJM Region that is capable of qualifying as an Existing Generation Capacity Resource as of the date on which bidding commences for an RPM Auction may not avoid the rule in subsection (a) or be removed from Capacity Resource status by failing to qualify as a Generation Capacity Resource, or by attempting to remove a unit previously qualified as a Generation Capacity Resource from classification as a Capacity Resource for that RPM Auction. However, generation resource may qualify for an exception to the RPM must-offer requirement, as shown by appropriate documentation, if the Capacity Market Seller that owns or controls such resource demonstrates that it: (i) is reasonably expected to be physically unable to participate in the relevant Delivery Year; (ii) has a financially and physically firm commitment to an external sale of its capacity, or (iii) was interconnected to the Transmission System as an Energy Resource and not subsequently converted to a Capacity Resource.

In order to establish that a resource is reasonably expected to be physically unable to participate in the relevant auction as set forth in (i) above, the Capacity Market Seller must demonstrate that:

A. It has a documented plan in place to retire the resource prior to or during the Delivery Year, and has submitted a notice of Deactivation to the Office of the Interconnection consistent with Tariff, Part V, section 113.1, without regard to whether the Office of the Interconnection has requested the Capacity Market Seller to continue to operate the resource beyond its desired deactivation date in accordance with Tariff, Part V, section 113.2 for the purpose of maintaining the reliability of the PJM Transmission System and the Capacity Market Seller has agreed to do so;

B. Significant physical operational restrictions cause long term or permanent changes to the installed capacity value of the resource, or the resource is under major repair that will extend into the applicable Delivery Year, that will result in the imposition of RPM performance penalties pursuant to Tariff, Attachment DD;

C. The Capacity Market Seller is involved in an ongoing regulatory proceeding (e.g. – regarding potential environmental restrictions) specific to the resource and has received an order, decision, final rule, opinion or other final directive from the regulatory authority that will result in the retirement of the resource; or

D. A resource considered an Existing Generating Capacity Resource because it cleared an RPM Auction for a Delivery Year prior to the Delivery Year of the relevant auction, but which is not yet in service, is unable to achieve full commercial operation prior to the Delivery Year of the relevant auction. The Capacity Market Seller must submit to the Office of the Interconnection and the Market Monitoring Unit a written sworn, notarized statement of a corporate officer certifying that the resource will not be in full commercial operation prior to the referenced Delivery Year.

In order to establish that a resource has a financially and physically firm commitment to an external sale of its capacity as set forth in (ii) above, the Capacity Market Seller must demonstrate that it has entered into a unit-specific bilateral transaction for service to load located outside the PJM Region, by a demonstration that such resource is identified on a unit-specific basis as a network resource under the transmission tariff for the control area applicable to such external load, or by an equivalent demonstration of a financially and physically firm commitment to an external sale. The Capacity Market Seller additionally shall identify the megawatt amount, export zone, and time period (in days) of the export.

A Capacity Market Seller that seeks approval for an exception to the RPM must-offer requirement, for any reason other than the reason specified in Paragraph A above, shall first submit such request in writing, along with all supporting data and documentation, to the Market Monitoring Unit for evaluation, notifying the Office of the Interconnection by copy of the same, by no later than one hundred twenty (120) days prior to the commencement of the offer period for the applicable RPM Auction.

In order to obtain an exception to the RPM must-offer requirement for the reason specified in Paragraph A above, a Capacity Market Seller shall first submit a preliminary exception request in writing, along with supporting data and documentation indicating the reasons and conditions upon which the Capacity Market Seller is relying in its analysis of whether to retire such resource, to the Market Monitoring Unit for evaluation, notifying the Office of the Interconnection by copy of the same, by no later than (a) November 1, 2013 for the Base Residual Auction for the 2017/2018 Delivery Year, (b) the September 1 that last precedes the Base Residual Auction for the 2018/2019 and subsequent Delivery Years, and (c) two hundred forty (240) days prior to the commencement of the offer period for the applicable Incremental Auction. By no later than five (5) Business Days after receipt of any such preliminary exception requests, the Office of the Interconnection will post on its website a summary of the number of megawatts of Generation Capacity Resources for which it has received notification of preliminary exception requests, on an aggregate basis by Zone and Locational Deliverability Area that comprises a subset of a Zone, as specified in the PJM Manuals.

Thereafter, as applicable, such Capacity Market Seller shall by no later than (a) the December 1 that last precedes the Base Residual Auction for the applicable Delivery Year, or (b) one hundred twenty (120) days prior to the commencement of the offer period for the applicable Incremental Auction, either (a) notify the Office of the Interconnection and the Market Monitoring Unit in writing that it is withdrawing its preliminary exception request and explaining the changes to its analysis of whether to retire such resource that support its decision to withdraw, or (b) demonstrate that it has met the requirements specified under Paragraph A above. By no later than five (5) Business Days after receipt of such notification, the Office of the Interconnection will post on its website a revised summary of the number of megawatts of Generation Capacity Resources for which it has received requests for exceptions to the RPM must-offer requirement for the reason specified in Paragraph A above, on an aggregate basis by Zone and Locational Deliverability Area that comprises a subset of a Zone, as specified in the PJM Manuals.

A Capacity Market Seller that seeks to remove a Generation Capacity Resource from Capacity Resource status shall first submit a preliminary request in writing, along with supporting data and documentation indicating the reasons and conditions upon which the Capacity Market Seller is relying in its analysis of whether to remove the Capacity Resource status of such resource to the Market Monitoring Unit for evaluation, notifying the Office of the Interconnection by copy of the same, by no later than (a) the September 1 that last precedes the Base Residual Auction, and (b) two hundred forty (240) days prior to the commencement of the offer period for the applicable Incremental Auction. For the Base Residual Auction for the 2023/2024 Delivery Year, a Capacity Market Seller that seeks to remove a Generation Capacity Resource from Capacity Resource status shall first submit such preliminary request by no later than November 1, 2019. By no later than five (5) Business Days after receipt of any such preliminary requests, the Office of the Interconnection will post on its website a summary of the number of megawatts of Generation Capacity Resources for which it has received notification of preliminary requests, on an aggregate basis by Zone and Locational Deliverability Area that comprises a subset of a Zone, as specified in the PJM Manuals.

Thereafter, as applicable, such Capacity Market Seller shall, by no later than (a) the December 1 that last precedes the Base Residual Auction for the applicable Delivery Year, or (b) one hundred twenty (120) days prior to the commencement of the offer period for the applicable Incremental Auction, notify the Office of the Interconnection and the Market Monitoring Unit in writing that it is either (a) withdrawing its preliminary request and explaining the changes to its analysis that support its decision to withdraw, or (b) confirming its preliminary decision to remove the Generation Capacity Resource from Capacity Resource status. By no later than five (5) Business Days after receipt of such notification, the Office of the Interconnection will post on its website a revised summary of the number of megawatts of Generation Capacity Resources for which it has received requests to remove its Capacity Resource status, on an aggregate basis by Zone and Locational Deliverability Area that comprises a subset of a Zone, as specified in the PJM Manuals.

The Market Monitoring Unit shall analyze the effects of the proposed removal of a Generation Capacity Resource from Capacity Resource status with regard to potential market power issues and shall notify the Capacity Market Seller and the Office of the Interconnection in writing of its determination of the request to remove the Generation Capacity Resource from Capacity Resource status, and whether a market power issue has been identified, by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction. Such notice shall include the specific market power impact resulting from the proposed removal of the Generation Capacity Resource from Capacity Resource status, as well as an initial assessment of any steps that could be taken to mitigate the market power impact.

A Capacity Market Seller may only remove the Generation Capacity Resource from Capacity Resource status if (i) the Market Monitoring Unit has determined that the Generation Capacity Resource meets the applicable criteria set forth in Tariff, Attachment DD, sections 5.6.6 and this section 6.6 and the Office of the Interconnection agrees with this determination, or (ii) the Commission has issued an order terminating the Capacity Resource status of the resource, or (iii) it is required as set forth in Tariff, Attachment DD, section 6.6A(c). Nothing herein shall require a Market Seller to offer its resource into an RPM Auction prior to seeking to remove a resource from Capacity Resource status, subject to satisfaction of this section 6.6. A Generation Capacity Resource that is removed from Capacity Resource status shall no longer qualify as an Existing Generation Capacity Resource, and the Capacity Interconnection Rights associated with such facility shall be subject to termination in accordance with the rules described in Tariff, Part VI, section 230.3.3. The Office of the Interconnection shall amend the applicable Interconnection Service Agreement or wholesale market participation agreement to reflect any such removal of the Capacity Interconnection Rights, and shall report the amended agreement to the Commission in the same manner as the original (e.g., FERC filing or Electronic Quarterly Reports). The Office of the Interconnection shall file the amended agreement unexecuted if the Interconnection Customer or wholesale market participant does not sign the amended Interconnection Service Agreement or wholesale market participation agreement.

If the Capacity Market Seller disagrees with the Market Monitoring Unit's determination of its request to remove a resource from Capacity Resource status or its request for an exception to the RPM must-offer requirement, it must notify the Market Monitoring Unit in writing, with a copy to the Office of the Interconnection, of the same by no later than eighty (80) days prior to the commencement of the offer period for the applicable RPM Auction. After the Market Monitoring Unit has made its determination of whether a resource may be removed from Capacity Resource status, or whether the resource meets one of the exceptions thereto, and has notified the Capacity Market Seller and the Office of the Interconnection of the same pursuant to Tariff, Attachment M-Appendix, section II.C.4, the Office of the Interconnection shall approve or deny the request. The request shall be deemed to be approved by the Office of the Interconnection, consistent with the determination of the Market Monitoring Unit, unless the Office of the Interconnection notifies the Capacity Market Seller and Market Monitoring Unit, by no later than sixty-five (65) days prior to the date on which the offer period for the applicable RPM Auction commences, that the request is denied.

If the Market Monitoring Unit does not timely notify the Capacity Market Seller and the Office of the Interconnection of its determination of the request to remove a Generation Capacity Resource from Capacity Resource status or for an exception to the RPM must-offer requirement, the Office of the Interconnection shall make the determination whether the request shall be approved or denied, and will notify the Capacity Market Seller of its determination in writing, with a copy to the Market Monitoring Unit, by no later than sixty-five (65) days prior to the date on which the offer period for the applicable RPM Auction commences.

After the Market Monitoring Unit and the Office of the Interconnection have made their determinations of whether a resource meets the criteria to qualify for an exception to the RPM must-offer requirement, the Capacity Market Seller must notify the Market Monitoring Unit and the Office of the Interconnection whether it intends to exclude from its Sell Offer some or all of the subject capacity on the basis of an identified exception by no later than sixty-five (65) days prior to the date on which the offer period for the applicable RPM Auction commences. PJM does not make determinations of whether withholding of capacity constitutes market power. A Generation Capacity Resource that does not qualify for submission into an RPM Auction because it is not owned or controlled by the Capacity Market Seller for a full Delivery Year is not subject to the offer requirement hereunder; provided, however, that a Capacity Market Seller planning to transfer ownership or control of a Generation Capacity Resource during a Delivery Year pursuant to a sale or transfer agreement entered into after March 26, 2009 shall be required to satisfy the offer requirement hereunder for the entirety of such Delivery Year and may satisfy such requirement by providing for the assumption of this requirement by the transferee of ownership or control under such agreement.

If a Capacity Market Seller doesn't timely seek to remove a Generation Capacity Resource from Capacity Resource status or timely submit a request for an exception to the RPM must-offer requirement, the Generation Capacity Resource shall only be removed from Capacity Resource status, and may only be approved for an exception to the RPM must-offer requirement, upon the Capacity Market Seller requesting and receiving an order from FERC, prior to the close of the offer period for the applicable RPM Auction, directing the Office of the Interconnection to remove the resource from Capacity Resource status and/or granting an exception to the RPM must-offer requirement or a waiver of the RPM must-offer requirement as to such resource.

(h) Any existing generation resource located in the PJM Region that satisfies the criteria in the definition of Existing Generation Capacity Resource as of the date on which bidding commences for the Base Residual Auction for a Delivery Year, that is not offered into such Base Residual Auction, and that does not meet any of the exceptions stated in the prior subsection (g): (i) may not participate in any subsequent Incremental Auctions conducted for such Delivery Year; (ii) shall not receive any payments under Tariff, Attachment DD, section 5.14 for such Delivery Year for the capacity of such Generation Capacity Resources; and (iii) shall not be permitted to satisfy any LSE's Unforced Capacity Obligation, or any entity's obligation to obtain the commitment of Capacity Resources, for such Delivery Year.

All generation resources located in the PJM Region that satisfy the criteria in the definition of Existing Generation Capacity Resource as of the date on which bidding commences for an Incremental Auction for a particular Delivery Year, but that did not satisfy such criteria as of the date that on which bidding commenced in the Base Residual Auction for that Delivery Year, that is not offered into that Incremental Auction, and that does not meet any of the exceptions stated in the prior subsection (g): (i) may not participate in any subsequent Incremental Auctions conducted for such Delivery Year; (ii) shall not receive any payments under Tariff, Attachment DD, section 5.14 for such Delivery Year for the capacity of such Generation Capacity Resources; and (iii) shall not be permitted to satisfy any LSE's Unforced Capacity Obligation, or any entity's obligation to obtain the commitment of Capacity Resources, for such Delivery Year.

All Existing Generation Capacity Resources that are offered into a Base Residual Auction or Incremental Auction for a particular Delivery Year but do not clear in such auction, that are not offered into each subsequent Incremental Auction, and that do not meet any of the exceptions stated in the prior subsection (g): (i) may not participate in any Incremental Auctions conducted for such Delivery Year subsequent to such failure to offer; (ii) shall not receive any payments under Tariff, Attachment DD, section 5.14 for such Delivery Year for the capacity of such Generation Capacity Resources; and (iii) shall not be permitted to satisfy any LSE's Unforced Capacity Obligation, or any entity's obligation to obtain the commitment of Capacity Resources, for such Delivery Year.

Any such Existing Generation Capacity Resources may also be subject to further action by the Market Monitoring Unit under the terms of Tariff, Attachment M and Tariff, Attachment M – Appendix.

(i) In addition to the remedies set forth in subsections (g) and (h) above, if the Market Monitoring Unit determines that one or more Capacity Market Sellers' failure to offer part or all of one or more existing generation resources, for which the Office of the Interconnection has not approved an exception to the RPM must-offer requirement, into an RPM Auction as required by this Section 6.6 would result in an increase of greater than five percent in any Zonal Capacity Price determined through such auction, and the Office of the Interconnection agrees with that determination, the Office of the Interconnection shall apply to FERC for an order, on an expedited basis, directing such Capacity Market Seller to participate in the relevant RPM Auction, or for other appropriate relief, and PJM will postpone clearing the auction pending FERC's decision on the matter. If the Office of the Interconnection disagrees with the Market Monitoring Unit's determination and does not apply to FERC for an order directing the Capacity Market Seller to participate in the auction or for other appropriate relief, the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and to seek appropriate relief.

6.6A Offer Requirement for Capacity Performance Resources

(a) For the 2018/2019 Delivery Year and subsequent Delivery Years, the installed capacity of every Generation Capacity Resource located in the PJM Region that is capable (or that reasonably can become capable) of qualifying as a Capacity Performance Resource shall be offered as a Capacity Performance Resource by the Capacity Market Seller that owns or controls all or part of such resource (which may include submission as Self-Supply) in all RPM Auctions for each such Delivery Year, less any amount determined by the Office of the Interconnection to be eligible for an exception to the Capacity Performance Resource must-offer requirement, where installed capacity is determined as of the date on which bidding commences for each RPM Auction pursuant to Tariff, Attachment DD, section 5.6.6.

(b) Determinations of EFORd and Unforced Capacity made under this section 6.6 as to a Generation Capacity Resource shall govern the offers required under this section as to the same Generation Capacity Resource.

(c) Exceptions to the requirement in subsection (a) shall be permitted only for a resource which the Capacity Market Seller demonstrates is reasonably expected to be physically incapable of satisfying the requirements of a Capacity Performance Resource. Intermittent Resources, Capacity Storage Resources, Demand Resources, and Energy Efficiency Resources shall not be required to offer as a Capacity Performance Resource, but shall not be precluded from being offered as a Capacity Performance Resource at a level that demonstrably satisfies such requirements. Exceptions shall be determined using the same timeline and procedures as specified in section 6.6.

Effective with the 2023/2024 Delivery Year, Capacity Market Sellers seeking an exception for a Base Residual Auction on the basis that a resource is incapable of meeting the Capacity Performance Resource requirement shall include a documented plan with the submission of their request showing the steps the Capacity Market Seller intends to pursue for the resource to become physically capable of satisfying the requirements of a Capacity Performance Resource. Such plan shall include (i) a timeline for design, permitting, procurement, and construction milestones, as applicable, where such timeline shall not exceed one Base Residual Auction exception, and (ii) evidence of corporate commitment (e.g., an SEC filing, a press release, or a letter from a duly authorized corporate officer indicating intent to make such investment). Periodic updates on the progress, shall be provided by the Capacity Market Seller to the Office of the Interconnection and the Market Monitoring Unit for their review by no later than (i) one hundred twenty (120) days prior to the commencement of the offer period for subsequent Incremental Auctions for the applicable Delivery Years, and (ii) the December 1 that last precedes subsequent Base Residual Auctions. The Capacity Market Seller shall also immediately notify the Office of the Interconnection and the Market Monitoring Unit of any material changes to the plan that may occur. Upon request by a Capacity Market Seller, a one year extension to the plan timeline shall be permissible only for delays not caused by the Capacity Market Seller, and that could not have been remedied through the exercise of due diligence by the Capacity Market Seller. In no event may an exception be requested by the Capacity Market Seller for more than two Base Residual Auctions.

Failure to submit a documented plan, or lack of good faith effort by a Capacity Market Seller to make an Existing Generation Capacity Resource physically capable of meeting the requirements of a Capacity Performance Resource in accordance with a documented plan, shall result in the removal of the resource's Capacity Resource status effective with the first future Delivery Year for which the resource was granted an exception, no earlier than the 2023/2024 Delivery Year. The Office of the Interconnection shall amend the applicable Interconnection Service Agreement or wholesale market participation agreement to reflect any such removal of the Capacity Interconnection Rights, and shall report the amended agreement to the Commission in the same manner as the original (e.g. FERC Filing or Electronic Quarterly Reports). The Office of the Interconnection shall file the amended agreement unexecuted if the Interconnection Customer or wholesale market participant does not sign the amended Interconnection Service Agreement or wholesale market participation agreement. The required change in Capacity Resource status shall only apply to those Generation Capacity Resources that are shown to be physically incapable of satisfying the requirements of a Capacity Performance Resource.

(d) A resource not exempted or excepted under subsection (c) hereof that is capable of qualifying as a Capacity Performance Resource and does not offer into an RPM Auction as a

Capacity Performance Resource shall be subject to the same restrictions on subsequent offers, and other possible remedies, as specified in section 6.6.

6.7 Data Submission

(a) Potential participants in any PJM Reliability Pricing Model Auction shall submit, together with supporting documentation for each item, to the Market Monitoring Unit and the Office of the Interconnection no later than one hundred twenty (120) days prior to the posted date for the conduct of such auction, a list of owned or controlled generation resources by PJM transmission zone for the specified Delivery Year, including the amount of gross capacity, the EFORd and the net (unforced) capacity. A potential participant intending to offer any Capacity Performance Resource at or below the default Market Seller Offer Cap described in Tariff, Attachment DD, section 6.4(a) must provide the associated offer cap and the MW to which the offer cap applies.

(b) Except as provided in subsection (c) below, potential participants in any PJM Reliability Pricing Model Auction in any LDA or Unconstrained LDA Group that request a unit specific Avoidable Cost Rate shall, in addition, submit the following data, together with supporting documentation for each item, to the Market Monitoring Unit no later than one hundred twenty (120) days prior to the commencement of the offer period for such auction:

i. If the Capacity Market Seller intends to submit a non-zero price in its Sell Offer in any such auction, the Capacity Market Seller shall submit a calculation of the Avoidable Cost Rate and Projected PJM Market Revenues, as defined in subsection (d) below, together with detailed supporting documentation.

ii. If the Capacity Market Seller intends to submit a Sell Offer based on opportunity cost, the Capacity Market Seller shall also submit a calculation of Opportunity Cost, as defined in subsection (d), with detailed supporting documentation.

(c) Potential auction participants identified in subsection (b) above need not submit the data specified in that subsection for any Generation Capacity Resource:

i. that is in an Unconstrained LDA Group or, if this is the relevant market, the entire PJM Region, and is in a resource class identified in the table below as not likely to include the marginal price-setting resources in such auction; or

ii. for which the potential participant commits that any Sell Offer it submits as to such resource shall not include any price above: (1) the applicable default level identified below for the relevant resource class, less (2) the Projected PJM Market Revenues for such resource, as determined in accordance with this Tariff.

Nothing herein precludes the Market Monitoring Unit from requesting additional information from any potential auction participant as deemed necessary by the Market Monitoring Unit, including, without limitation, additional cost data on resources in a class that is not otherwise expected to include the marginal price setting resource as outlined in Tariff, Attachment M-Appendix, section II.G. Any Sell Offer submitted in any auction that is inconsistent with any agreement or commitment made pursuant to this subsection shall be rejected, and the Capacity Market Seller shall be required to resubmit a Sell Offer that complies with such agreement or commitment within one (1) Business Day of the Office of the Interconnection's rejection of such Sell Offer. If the Capacity Market Seller does not timely resubmit its Sell Offer, fails to request a unit-specific Avoidable Cost Rate by the specified deadline, or if the Office of the Interconnection determines that the information provided by the Capacity Market Seller in support of the requested unit-specific Avoidable Cost Rate or Sell Offer is incomplete, the Capacity Market Seller shall be deemed to have submitted a Sell Offer that complies with the commitments made under this subsection, with a default offer for the applicable class of resource or nearest comparable class of resource determined under this subsection (c)(ii). The obligation imposed under section 6.6(a) above shall not be satisfied unless and until the Capacity Market Seller submits (or is deemed to have submitted) a Sell Offer that conforms to its commitments made pursuant to this subsection or subject to the procedures set forth in section 6.4 above and Tariff, Attachment M-Appendix, section II.H.

The default retirement and mothball Avoidable Cost Rates ("ACR") referenced in this subsection (c)(ii) are as set forth in the tables below for the 2013/2014 Delivery Year through the 2016/2017 Delivery Year. Capacity Market Sellers shall use the one-year mothball Avoidable Cost Rate shown below, unless such Capacity Market Seller satisfies the criteria set forth in section 6.7(e) below, in which case the Capacity Market Seller may use the retirement Avoidable Cost Rate. PJM shall also publish on its Web site the number of Generation Capacity Resources and megawatts per LDA that use the retirement Avoidable Cost Rates. A Capacity Market Seller may not use the default Market Seller Offer Cap contained in the ACR tables in this subsection, and also seek to include any one or more categories of the Avoidable Cost Rate defined section 6.8 below.

Maximum Avoidable Cost Rates by Technology Class

Technology	**2013/14 Mothball ACR ($/MW-Day)**	**2013/14 Retirement ACR ($/MW-Day)**	**2014/15 Mothball ACR ($/MW-Day)**	**2014/15 Retirement ACR ($/MW-Day)**	**2015/16 Mothball ACR ($/MW-Day)**	**2015/16 Retirement ACR ($/MW-Day)**	**2016/2017 Mothball ACR ($/MW-Day)**	**2016/2017 Retirement ACR ($/MW-Day)**
Nuclear	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pumped Storage	$23.64	$33.19	$24.56	$34.48	$25.56	$35.89	$24.05	$33.78
Hydro	$80.80	$105.67	$83.93	$109.76	$87.35	$114.24	$82.23	$107.55
Sub-Critical Coal	$193.98	$215.02	$201.49	$223.35	$209.71	$232.46	$197.43	$218.84
Super Critical Coal	$200.41	$219.21	$208.17	$227.70	$216.66	$236.99	$203.96	$223.10
Waste Coal - Small	$255.81	$309.83	$265.72	$321.83	$276.56	$334.96	$260.35	$315.34
Waste Coal – Large	$94.61	$114.29	$98.27	$118.72	$102.28	$123.56	$96.29	$116.32
Wind	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CC-2 on 1 Frame F	$35.18	$49.90	$36.54	$51.83	$38.03	$53.94	$35.81	$50.79
CC-3 on 1 Frame	$39.06	$52.89	$40.57	$54.94	$42.23	$57.18	$39.75	$53.83

E/Siemens								
CC–3 or More on 1 or More Frame F	$30.46	$42.28	$31.64	$43.92	$32.93	$45.71	$30.99	$43.03
CC-NUG Cogen. Frame B or E Technology	$130.76	$175.71	$135.82	$182.52	$141.36	$189.97	$133.09	$178.83
CT - 1st & 2nd Gen. Aero (P&W FT 4)	$27.96	$37.19	$29.04	$38.63	$30.22	$40.21	$28.45	$37.85
CT - 1st & Gen. Frame B	$27.63	$36.87	$28.70	$38.30	$29.87	$39.86	$28.11	$37.52
CT - 2nd Gen. Frame E	$26.26	$35.14	$27.28	$36.50	$28.39	$37.99	$26.73	$35.77
CT - 3rd Gen. Aero (GE LM 6000)	$63.57	$93.70	$66.03	$97.33	$68.72	$101.30	$64.70	$95.37
CT - 3rd Gen. Aero (P&W FT - 8 TwinPak)	$33.34	$49.16	$34.63	$51.06	$36.04	$53.14	$33.93	$50.03
CT - 3rd Gen. Frame F	$26.96	$38.83	$28.00	$40.33	$29.14	$41.98	$27.43	$39.52
Diesel	$29.92	$37.98	$31.08	$39.45	$32.35	$41.06	$30.44	$38.66
Oil and Gas Steam	$74.20	$90.33	$77.07	$93.83	$80.21	$97.66	$75.51	$91.94

Commencing with the Base Residual Auction for the 2017/2018 Delivery Year, the Office of the Interconnection shall determine the default retirement and mothball Avoidable Cost Rates referenced in section (c)(ii) above, and post them 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 applicable ACR rates, the Office of the Interconnection shall use the actual rate of change in the historical values from the Handy-Whitman Index of Public Utility Construction Costs or a comparable index approved by the Commission ("Handy-Whitman Index") to the extent they are available to update the base values for the Delivery Year, and for future Delivery Years for which the updated Handy-Whitman Index values are not yet available the Office of the Interconnection shall update the base values for the Delivery Year using the most recent ten-calendar-year annual average rate of change. The ACR rates shall be expressed in dollar values for the applicable Delivery Year.

Maximum Avoidable Cost Rates by Technology Class (Expressed in 2011 Dollars for the 2011/2012 Delivery Year)		
Technology	**Mothball ACR ($/MW-Day)**	**Retirement ACR ($/MW-Day)**
Combustion Turbine - Industrial Frame	$24.13	$33.04
Coal Fired	$136.91	$157.83
Combined Cycle	$29.58	$40.69
Combustion Turbine - Aero Derivative	$26.13	$37.18
Diesel	$25.46	$32.33
Hydro	$68.78	$89.96
Oil and Gas Steam	$63.16	$76.90
Pumped Storage	$20.12	$28.26

To determine the default retirement and mothball ACR values for the 2017/2018 Delivery Year, the Office of the Interconnection shall multiply the base default retirement and mothball ACR values in the table above by a factor equal to one plus the most recent annual average rate of change in the July Handy-Whitman Indices for the 2011 to 2013 calendar years to determine updated base default retirement and mothball ACR values. The updated base default retirement and mothball ACR values shall then be multiplied by a factor equal to one plus the most recent ten-calendar-year annual average rate of change in the applicable Handy-Whitman Index, taken to the fourth power, as calculated by the Office of the Interconnection and posted to its website.

To determine the default retirement and mothball ACR values for the 2018/2019 and 2019/2020 Delivery Years for Base Capacity Resources, the Office of the Interconnection shall multiply the updated base default retirement and mothball ACR values from the immediately preceding Delivery Year by a factor equal to one plus the most recent annual average rate of change in the July Handy-Whitman Index. These values become the new adjusted base default retirement and mothball ACR values, as calculated by the Office of the Interconnection and posted to its website. These resulting adjusted base values for the Delivery Year shall be multiplied by a factor equal to one plus the most recent ten-calendar-year annual average rate of change in the applicable Handy-Whitman Index, taken to the fourth power, as calculated by the Office of the Interconnection and posted to its website.

PJM shall also publish on its website the number of Generation Capacity Resources and megawatts per LDA that use the retirement Avoidable Cost Rates.

After the Market Monitoring Unit conducts its annual review of the table of default Avoidable Cost Rates included in section 6.7(c) above in accordance with the procedure specified in Tariff, Attachment M-Appendix, section II.H, it will provide updated values or notice of its determination that updated values are not needed to Office of the Interconnection. In the event that the Office of the Interconnection determines that the values should be updated, the Office of the Interconnection shall file its proposed values with the Commission by no later than October 30th prior to the commencement of the offer period for the first RPM Auction for which it proposes to apply the updated values.

(d) In order for costs to qualify for inclusion in the Market Seller Offer Cap, the Capacity Market Seller must provide to the Market Monitoring Unit and the Office of the Interconnection relevant unit-specific cost data concerning each data item specified as set forth in section 6 by no later than one hundred twenty (120) days prior to the commencement of the offer period for the applicable RPM Auction. If cost data is not available at the time of submission for the time periods specified in section 6.8 below, costs may be estimated for such period based on the most recent data available, with an explanation of and basis for the estimate used, as may be further specified in the PJM Manuals. Based on the data and calculations submitted by the Capacity Market Sellers for each existing generation resource and the formulas specified below, the Market Monitoring Unit shall calculate the Market Seller Offer Cap for each such resource, and notify the Capacity Market Seller and the Office of the Interconnection in writing of its determination pursuant to Tariff, Attachment M-Appendix, section II.E.

i. Avoidable Cost Rate: The Avoidable Cost Rate for an existing generation resource shall be determined using the formula below and applied to the unit's Base Offer Segment.

ii. Opportunity Cost: Opportunity Cost shall be the documented price available to an existing generation resource in a market external to PJM. In the event that the total MW of existing generation resources submitting opportunity cost offers in any auction for a Delivery Year exceeds the firm export capability of the PJM system for such Delivery Year, or the capability of external markets to import capacity in such year, the Office of the Interconnection will accept such offers on a competitive basis. PJM will construct a supply curve of opportunity cost offers, ordered by opportunity cost, and accept such offers to export starting with the highest opportunity cost, until the maximum level of such exports is reached. The maximum level of such exports is the lesser of the Office of the Interconnection's ability to permit firm exports or the ability of the importing area(s) to accept firm imports or imports of capacity, taking account of relevant export limitations by location. If, as a result, an opportunity cost offer is not accepted from an existing generation resource, the Market Seller Offer Cap applicable to Sell Offers relying on such generation resource shall be the Avoidable Cost Rate less the Projected Market Revenues for such resource (as defined in section 6.4 above). The default Avoidable Cost Rate shall be the one year mothball Avoidable Cost Rate set forth in the tables in section 6.7(c) above unless Capacity Market Seller satisfies the criteria delineated in section 6.7(e) below.

iii. Projected PJM Market Revenues: Projected PJM Market Revenues are defined by section 6.8(d) below, for any Generation Capacity Resource to which the Avoidable Cost Rate is applied.

(e) In order for the retirement Avoidable Cost Rate set forth in the table in section 6.7(c) to apply, by no later than one hundred twenty (120) days prior to the commencement of the offer period for the applicable RPM Auction, a Capacity Market Seller must submit to the Office of the Interconnection and the Market Monitoring Unit a written sworn, notarized statement of a corporate officer representing that the Capacity Market Seller will retire the Generation Capacity Resource if it does not receive during the relevant Delivery Year at least the applicable retirement Avoidable Cost Rate because it would be uneconomic to continue to operate the Generation Capacity Resource in the Delivery Year without the retirement Avoidable Cost Rate, and specifying the date the Generation Capacity Resource would otherwise be retired.

6.8 Avoidable Cost Definition

(a) **Avoidable Cost Rate**:

The Avoidable Cost Rate for a Generation Capacity Resource that is the subject of a Sell Offer shall be determined using the following formula, expressed in dollars per MW-year:

Avoidable Cost Rate = [Adjustment Factor * (AOML + AAE + AFAE + AME + AVE + ATFI + ACC + ACLE) + ARPIR + APIR + CPQR]

Where:

- **Adjustment Factor** equals 1.10 (to provide a margin of error for understatement of costs) plus an additional adjustment referencing the 10-year average Handy-Whitman Index in order to account for expected inflation from the time interval between the submission of the Sell Offer and the commencement of the Delivery Year.

- **AOML (Avoidable Operations and Maintenance Labor)** consists of the avoidable labor expenses related directly to operations and maintenance of the generating unit for the twelve months preceding the month in which the data must be provided. The categories of expenses included in AOML are those incurred for: (a) on-site based labor engaged in operations and maintenance activities; (b) off-site based labor engaged in on-site operations and maintenance activities directly related to the generating unit; and (c) off-site based labor engaged in off-site operations and maintenance activities directly related to generating unit equipment removed from the generating unit site.

    - **AAE (Avoidable Administrative Expenses)** consists of the avoidable administrative expenses related directly to employees at the generating unit for twelve months preceding the month in which the data must be provided. The categories of expenses included in AAE are those incurred for: (a) employee expenses (except employee expenses included in AOML); (b) environmental fees; (c) safety and operator training; (d) office supplies; (e) communications; and (f) annual plant test, inspection and analysis.

- **AFAE (Avoidable Fuel Availability Expenses) c**onsists of avoidable operating expenses related directly to fuel availability and delivery for the generating unit that can be demonstrated by the Capacity Market Seller based on data for the twelve months preceding the month in which the data must be provided , or on reasonable projections for the Delivery Year supported by executed contracts, published tariffs, or other data sufficient to demonstrate with reasonable certainty the level of costs that have been or shall be incurred for such purpose. The categories of expenses included in AFAE are those incurred for: (a) firm gas pipeline transportation; (b) natural gas storage costs; (c) costs of gas balancing agreements; and (d) costs of gas park and loan services. AFAE expenses are for firm fuel supply and apply solely for offers for a Capacity Performance Resource

- **AME (Avoidable Maintenance Expenses)** consists of avoidable maintenance expenses (other than expenses included in AOML) related directly to the generating unit for the twelve months preceding the month in which the data must be provided. The categories of expenses included in AME are those incurred for: (a) chemical and materials consumed during maintenance of the generating unit; and (b) rented maintenance equipment used to maintain the generating unit.

- **AVE (Avoidable Variable Expenses)** consists of avoidable variable expenses related directly to the generating unit incurred in the twelve months preceding the month in which the data must be provided. The categories of expenses included in AVE are those incurred for: (a) water treatment chemicals and lubricants; (b) water, gas, and electric service (not for power generation); and (c) waste water treatment.

- **ATFI (Avoidable Taxes, Fees and Insurance)** consists of avoidable expenses related directly to the generating unit incurred in the twelve months preceding the month in which the data must be provided. The categories of expenses included in AFTI are those incurred for: (a) insurance, (b) permits and licensing fees, (c) site security and utilities for maintaining security at the site; and (d) property taxes.

- **ACC (Avoidable Carrying Charges)** consists of avoidable short-term carrying charges related directly to the generating unit in the twelve months preceding the month in which the data must be provided. Avoidable short-term carrying charges shall include short term carrying charges for maintaining reasonable levels of inventories of fuel and spare parts that result from short-term operational unit decisions as measured by industry best practice standards. For the purpose of determining ACC, short term is the time period in which a reasonable replacement of inventory for normal, expected operations can occur.

- **ACLE (Avoidable Corporate Level Expenses)** consists of avoidable corporate level expenses directly related to the generating unit incurred in the twelve months preceding the month in which the data must be provided. Avoidable corporate level expenses shall include only such expenses that are directly linked to providing tangible services required for the operation of the generating unit proposed for Deactivation. The categories of avoidable expenses included in ACLE are those incurred for: (a) legal services, (b) environmental reporting; and (c) procurement expenses.

- **CPQR (Capacity Performance Quantifiable Risk)** consists of the quantifiable and reasonably-supported costs of mitigating the risks of non-performance associated with submission of a Capacity Performance Resource offer (or of a Base Capacity Resource offer for the 2018/19 or 2019/20 Delivery Years), such as insurance expenses associated with resource non-performance risks. CPQR shall be considered reasonably supported if it is based on actuarial practices generally used by the industry to model or value risk and if it is based on actuarial practices used by the Capacity Market Seller to model or value risk in other aspects of the Capacity Market Seller's business. Such reasonable support shall also include an officer certification that the modeling and valuation of the CPQR was developed in accord with such practices. Provision of such reasonable support shall be sufficient to establish the CPQR. A Capacity Market Seller may use other methods or forms of support for its proposed CPQR that shows the CPQR is limited to risks the seller faces from committing a Capacity Resource hereunder, that quantifies the costs of mitigating such risks, and that includes supporting documentation (which may include an officer certification) for the identification of such risks and quantification of such costs. Such showing shall establish the proposed CPQR upon acceptance by the Office of the Interconnection.

- **APIR (Avoidable Project Investment Recovery Rate) = PI * CRF**

Where:

  - **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.

- **CRF** is the annual capital recovery factor from the following table, applied in accordance with the terms specified below.

Age of Existing Units (Years)	Remaining Life of Plant (Years)	Levelized CRF
1 to 5	30	0.107
6 to 10	25	0.114
11 to 15	20	0.125
16 to 20	15	0.146
21 to 25	10	0.198
25 Plus	5	0.363
Mandatory CapEx	4	0.450
40 Plus Alternative	1	1.100

Unless otherwise stated, Age of Existing Unit shall be equal to the number of years since the Unit commenced commercial operation, up to and through the relevant Delivery Year.

Remaining Life of Plant defines the amortization schedule (i.e., the maximum number of years over which the Project Investment may be included in the Avoidable Cost Rate.)

Capital Expenditures and Project Investment

For any given Project Investment, a Capacity Market Seller may make a one-time election to recover such investment using: (i) the highest CRF and associated recovery schedule to which it is entitled; or (ii) the next highest CRF and associated recovery schedule. For these purposes, the CRF and recovery schedule for the 25 Plus category is the next highest CRF and recovery schedule for both the Mandatory CapEx and the 40 Plus Alternative categories. The Capacity Market Seller using the above table must provide the Market Monitoring Unit with information, identifying and supporting such election, including but not limited to the age of the unit, the amount of the Project Investment, the purpose of the investment, evidence of corporate commitment (e.g., an SEC filing, a press release, or a letter from a duly authorized corporate officer indicating intent to make such investment), and detailed information concerning the governmental requirement (if applicable). Absent other written notification, such election shall be deemed based on the CRF such Seller employs for the first Sell Offer reflecting recovery of any portion of such Project Investment.

For any resource using the CRF and associated recovery schedule from the CRF table that set the Capacity Resource Clearing Price in any Delivery Year, such Capacity Market Seller must also provide to the Market Monitoring Unit, for informational purposes only, evidence of the actual expenditure of the Project Investment, when such information becomes available.

If the project associated with a Project Investment that was included in a Sell Offer using a CRF and associated recovery schedule from the above table has not entered into commercial operation prior to the end of the relevant Delivery Year, and the resource's Sell Offer sets the clearing price for the relevant LDA, the Capacity Market Seller shall be required to elect to either (i) pay a charge that is equal to the difference between the Capacity Resource Clearing Price for such LDA for the relevant Delivery Year and what the clearing price would have been absent the

APIR component of the Avoidable Cost Rate, this difference to be multiplied by the cleared MW volume from such Resource ("rebate payment"); (ii) hold such rebate payment in escrow, to be released to the Capacity Market Seller in the event that the project enters into commercial operation during the subsequent Delivery Year or rebated to LSEs in the relevant LDA if the project has not entered into commercial operation during the subsequent Delivery Year; or (iii) make a reasonable investment in the amount of the PI in other Existing Generation Capacity Resources owned or controlled by the Capacity Market Seller or its Affiliates in the relevant LDA. The revenue from such rebate payments shall be allocated pro rata to LSEs in the relevant LDA(s) that were charged a Locational Reliability Charge for such Delivery Year, based on their Daily Unforced Capacity Obligation in the relevant LDA(s). If the Sell Offer from the Generation Capacity Resource did not set the Capacity Resource Clearing Price in the relevant LDA, no alternative investment or rebate payment is required. If the difference between the Capacity Resource Clearing Price for such LDA for the relevant Delivery Year and what the clearing price would have been absent the APIR amount does not exceed the greater of $10 per MW-day or a 10% increase in the clearing price, no alternative investment or rebate payment is required.

Mandatory CapEx Option

The Mandatory CapEx CRF and recovery schedule is an option available, beginning in the third BRA (Delivery Year 2009-10), to a resource that must make a Project Investment to comply with a governmental requirement that would otherwise materially impact operating levels during the Delivery Year, where: (i) such resource is a coal, oil or gas-fired resource that began commercial operation no fewer than fifteen years prior to the start of the first Delivery Year for which such recovery is sought, and such Project Investment is equal to or exceeds $200/kW of capitalized project cost; or (ii) such resource is a coal-fired resource located in an LDA for which a separate VRR Curve has been established for the relevant Delivery Years, and began commercial operation at least 50 years prior to the conduct of the relevant BRA.

A Capacity Market Seller that wishes to elect the Mandatory CapEx option for a Project Investment must do so beginning with the Base Residual Auction for the Delivery Year in which such project is expected to enter commercial operation. A Sell Offer submitted in any Base Residual Auction for which the Mandatory CapEx option is selected may not exceed an offer price equivalent to 0.90 times the then-current Net CONE (on an unforced-equivalent basis).

40 Plus Alternative Option

The 40 Plus Alternative CRF and recovery schedule is an option available, beginning in the third BRA (Delivery Year 2009-10), for a resource that is a gas- or oil-fired resource that began commercial operation no less than 40 years prior to the conduct of the relevant BRA (excluding, however, any resource in any Delivery Year for which the resource is receiving a payment under Tariff, Part V. Generation Capacity Resources electing this 40 Plus Alternative CRF shall be treated as At Risk Generation for purposes of the sensitivity runs in the RTEP process). Resources electing the 40 Plus Alternative option will be modeled in the RTEP process as "at-risk" at the end of the one-year amortization period.

A Capacity Market Seller that wishes to elect the 40 Plus Alternative option for a Project Investment must provide written notice of such election to the Office of the Interconnection no later than six months prior to the Base Residual Auction for which such election is sought; provided however that shorter notice may be provided if unforeseen circumstances give rise to the need to make such election and such seller gives notice as soon as practicable.

The Office of the Interconnection shall give market participants reasonable notice of such election, subject to satisfaction of requirements under the PJM Operating Agreement for protection of confidential and commercially sensitive information. A Sell Offer submitted in any Base Residual Auction for which the 40 Plus Alternative option is selected may not exceed an offer price equivalent to the then-current Net CONE (on an unforced-equivalent basis).

Multi-Year Pricing Option

A Seller submitting a Sell Offer with an APIR component that is based on a Project Investment of at least $450/kW may elect this Multi-Year Pricing Option by providing written notice to such effect the first time it submits a Sell Offer that includes an APIR component for such Project Investment. Such option shall be available on the same terms, and under the same conditions, as are available to Planned Generation Capacity Resources under Tariff, Attachment DD, section 5.14(c).

- **ARPIR (Avoidable Refunds of Project Investment Reimbursements)** consists of avoidable refund amounts of Project Investment Reimbursements payable by a Generation Owner to PJM under Tariff, Part V, section 118 or avoidable refund amounts of project investment reimbursements payable by a Generation Owner to PJM under a Cost of Service Recovery Rate filed under Tariff, Part V, section 119 and approved by the Commission.

(b) For the purpose of determining an Avoidable Cost Rate, avoidable expenses are incremental expenses directly required to operate a Generation Capacity Resource that a Generation Owner would not incur if such generating unit did not operate in the Delivery Year or meet Availability criteria during Peak-Hour Periods during the Delivery Year.

(c) Variable costs that are directly attributable to the production of energy shall be excluded from a Market Seller's generation resource Avoidable Cost Rate. Notwithstanding the foregoing, a Market Seller that included variable costs attributable to the production of energy in a generation resource's Avoidable Cost Rate prior to April 15, 2019 shall not include such costs in such generation resource's Maintenance Adders or Operating Costs for any Delivery Year for which it has already included such costs in the generation resource's Avoidable Cost Rate. A Market Seller implicated by this paragraph may continue including such variable costs attributable to the production of energy in its Avoidable Cost Rate for each generation resource for any Delivery Year for which it already did so prior to April 15, 2019.

(d) Projected PJM Market Revenues for any Generation Capacity Resource to which the Avoidable Cost Rate is applied shall include all actual unit-specific revenues from PJM energy markets, ancillary services, and unit-specific bilateral contracts from such Generation Capacity Resource, net of energy and ancillary services market offers for such resource. Net energy market revenues shall be based on the non-zero market-based offers of the Capacity

Market Seller of such Generation Capacity Resource unless one of the following conditions is met, in which case the cost-based offer shall be used: (x) the market-based offer for the resource is zero, (y) the market-based offer for the resource is higher than its cost-based offer and such offer has been mitigated, or (z) the market-based offer for the resource is less than such Capacity Market Seller's fuel and environmental costs for the resource which shall be determined either by directly summing the fuel and environmental costs if they are available, or by subtracting from the cost-based offer for the resource all costs developed pursuant to the Operating Agrement and PJM Manuals that are not fuel or environmental costs.

The calculation of Projected PJM Market Revenues shall be equal to the rolling simple average of such net revenues as described above from the three most recent whole calendar years prior to the year in which the BRA is conducted.

If a Generation Capacity Resource did not receive PJM market revenues during the entire relevant time period because the Generation Capacity Resource was not integrated into PJM during the full period, then the Projected PJM Market Revenues shall be calculated using only those whole calendar years within the full period in which such Resource received PJM market revenues.

If a Generation Capacity Resource did not receive PJM market revenues during the entire relevant time period because it was not in commercial operation during the entire period, or if data is not available to the Capacity Market Seller for the entire period, despite the good faith efforts of such seller to obtain such data, then the Projected PJM Market Revenues shall be calculated based upon net revenues received over the entire period by comparable units, to be developed by the MMU and the Capacity Market Seller.

ATTACHMENT DD-1

Preface: The provisions of this Attachment incorporate into the Tariff for ease of reference the provisions of Schedule 6 of the Reliability Assurance Agreement among Load Serving Entities in the PJM Region. As a result, this Attachment will be modified, subject to FERC approval, so that the terms and conditions set forth herein remain consistent with the corresponding terms and conditions of RAA, Schedule 6. Capitalized terms used herein that are not otherwise defined in Tariff, Attachment DD or elsewhere in this Tariff have the meaning set forth in the RAA.

PROCEDURES FOR DEMAND RESOURCES AND ENERGY EFFICIENCY

A. Parties can partially or wholly offset the amounts payable for the Locational Reliability Charge with Demand Resources that are operated under the direction of the Office of the Interconnection. FRR Entities may reduce their capacity obligations with Demand Resources that are operated under the direction of the Office of the Interconnection and detailed in such entity's FRR Capacity Plan. Demand Resources qualifying under the criteria set forth below may be offered for sale or designated as Self-Supply in the Base Residual Auction, included in an FRR Capacity Plan, or offered for sale in any Incremental Auction, for any Delivery Year for which such resource qualifies. Qualified Demand Resources generally fall in one of two categories, i.e., Guaranteed Load Drop or Firm Service Level, as further specified in section G below and the PJM Manuals. Qualified Demand Resources may be provided by a Curtailment Service Provider, notwithstanding that such Curtailment Service Provider is not a Party to this Agreement. Such Curtailment Service Providers must satisfy the requirements hereof and the PJM Manuals.

1. A Party must formally notify, in accordance with the requirements of the PJM Manuals and section F hereof, as applicable, the Office of the Interconnection of the Demand Resource Registration that it is placing under the direction of the Office of the Interconnection. A Party must further notify the Office of the Interconnection whether the Demand Resource Registration is linked to a Limited Demand Resource, an Extended Summer Demand Resource, a Base Capacity Demand Resource, a Summer-Period Demand Resource or an Annual Demand Resource.

2. A Demand Resource Registration must achieve its full load reduction within the following time period:

(a) For the 2015/2016 Delivery Year and subsequent Delivery Years, a Demand Resource Registration must be able to fully respond to a Load Management Event within 30 minutes of notification from the Office of the Interconnection. This default 30 minute prior notification shall apply unless a Curtailment Service Provider obtains an exception from the Office of the Interconnection due to physical operational limitations that prevent the Demand Resource Registration from reducing load within that timeframe. In such case, the Curtailment Service Provider shall submit a request for an exception to the 30 minute prior notification requirement to the Office of the Interconnection, at the time the Registration Form for that Demand Resource Registration is submitted in accordance with Tariff, Attachment K-Appendix. The only alternative notification times that the Office of Interconnection will permit, upon approval of an exception request, are 60 minutes and 120 minutes prior to a Load Management Event. The Curtailment Service Provider shall indicate in writing, in the appropriate application, that it seeks an exception to permit a prior notification time of 60 minutes or 120 minutes, and the reason(s) for the requested exception. A Curtailment Service Provider shall not submit a request for an exception to the default 30 minute notification period unless it has done its due diligence to confirm that the Demand Resource Registration is physically incapable of responding within that timeframe based on one or more of the reasons set forth below and as may be further defined in the PJM Manuals and has obtained detailed data and documentation to support this determination.

In order to establish that a Demand Resource Registration is reasonably expected to be physically unable to reduce load in that timeframe, the Curtailment Service Provider that submitted the Demand Resource Registration must demonstrate that:

(i) The manufacturing processes for the Demand Resource Registration require gradual reduction to avoid damaging major industrial equipment used in the manufacturing process, or damage to the product generated or feedstock used in the manufacturing process;

(ii) Transfer of load to back-up generation requires time-intensive manual process taking more than 30 minutes;

(iii) On-site safety concerns prevent location from implementing reduction plan in less than 30 minutes; or,

(iv) The Demand Resource Registration is comprised of mass market residential customers or Small Commercial Customers which collectively cannot be notified of a Load Management Event within a 30-minute timeframe due to unavoidable communications latency, in which case the requested notification time shall be no longer than 120 minutes.

The Office of the Interconnection may request data and documentation from the Curtailment Service Provider and such Curtailment Service Provider shall provide to the Office of the Interconnection within three (3) Business Days of a request therefor, a copy of all of the data and documentation supporting the exception request. Failure to provide a timely response to such request shall cause the exception to terminate the following Operating Day.

At its sole option and discretion, the Office of the Interconnection may review the data and documentation provided by the Curtailment Service Provider to determine if the Demand Resource Registration has met one or more of the criteria above. The Office of the

Interconnection will notify the Curtailment Service Provider in writing of its determination by no later than ten (10) Business Days after receipt of the data and documentation.

The Curtailment Service Provider shall provide written notification to the Office of the Interconnection of a material change to the facts that supported its exception request within three (3) Business Days of becoming aware of such material change in facts, and, if the Office of Interconnection determines that the physical limitation criteria above are no longer being met, the Demand Resource Registration shall be subject to the default notification period of 30 minutes immediately upon such determination.

3. The initiation of load reduction, upon the request of the Office of the Interconnection, must be within the authority of the dispatchers of the Party. No additional approvals should be required.

4. The initiation of load reduction upon the request of the Office of the Interconnection is considered a pre-emergency or emergency action and must be implementable prior to a voltage reduction.

5. A Curtailment Service Provider intending to offer for sale or designate for self-supply, a Demand Resource in any RPM Auction, or intending to include a Demand Resource in any FRR Capacity Plan must demonstrate, to PJM's satisfaction, that such resource shall have the capability to provide a reduction in demand, or otherwise control load, on or before the start of the Delivery Year for which such resource is committed. As part of such demonstration, each such Curtailment Service Provider shall submit a Demand Resource Sell Offer Plan in accordance with the standards and procedures set forth in RAA, Schedule 6, section A-1; RAA, Schedule 8.1 (as to FRR Capacity Plans) and the PJM Manuals, no later than 30 days prior to, as applicable, the RPM Auction in which such resource is to be offered, or the deadline for submission of the FRR Capacity Plan in which such resource is to be included. PJM may verify the Curtailment Service Provider's adherence to the Demand Resource Sell Offer Plan at any time. A Curtailment Service Provider with a PJM-approved Demand Resource Sell Offer Plan will be permitted to offer up to the approved Demand Resource quantity into the subject RPM Auction or include such resource in its FRR Capacity Plan.

6. Selection of a Demand Resource in an RPM Auction results in commitment of capacity to the PJM Region. Demand Resources that are so committed must be linked to registrations participating in the Full Program Option or Capacity Only Option of the Emergency Load Response and Pre-Emergency Load Response Program and thus available for dispatch during PJM-declared pre-emergency events and emergency events.

A-1. A Demand Resource Sell Offer Plan shall consist of a completed template document in the form posted on the PJM website, requiring the information set forth below and in the PJM Manuals, and a Demand Resource Officer Certification Form signed by an officer of the Demand Resource Provider that is duly authorized to provide such a certification. The Demand Resource Sell Offer Plan must provide information that supports the Demand Resource Provider's intended Demand Resource Sell Offers and demonstrates that the Demand Resources are being offered with the intention that the MW quantity that clears the auction is reasonably expected to be physically delivered through Demand Resource registrations for the relevant Delivery Year. The Demand Resource Sell Offer Plan shall include all Existing Demand Resources and all Planned Demand Resources that the Demand Resource Provider intends to offer into an RPM Auction or include in an FRR Capacity Plan.

1. Demand Resource Sell Offer Plan Template. The Demand Resource Sell Offer Plan template, in the form provided on the PJM website, shall require the Demand Resource Provider to provide the following information and such other information as specified in the PJM Manuals:

(a) Summary Information. The completed template shall include the Demand Resource Provider's company name, contact information, and the Nominated DR Value in ICAP MWs by Zone/sub-Zone that the Demand Resource Provider intends to offer, stated separately for Existing Demand Resources and Planned Demand Resources. The total Nominated DR Value in MWs for each Zone/sub-Zone shall be the sum of the Nominated DR Value of Existing Demand Resources and the Nominated DR Value of Planned Demand Resources, and shall be the maximum MW amount the Provider intends to offer in the RPM Auction for the indicated Zone/sub-Zone, provided that nothing herein shall preclude the Demand Resource Provider from offering in the auction a lesser amount than the total Nominated DR Value shown in its Demand Resource Sell Offer Plan.

(b) Existing Demand Resources. The Demand Resource Provider shall identify all Existing Demand Resources by identifying end-use customer sites that are currently registered with PJM (even if not registered by such Demand Resource Provider) and that the Demand Resource Provider reasonably expects to have under a contract to reduce load based on PJM dispatch instructions by the start of the auction Delivery Year.

(c) Planned Demand Resources. The Demand Resource Provider shall provide the details of, and key assumptions underlying, the Planned Demand Resource quantities (i.e., all Demand Resource quantities in excess of Existing Demand Resource quantities) contained in the Demand Resource Sell Offer Plan, including:

(i) key program attributes and assumptions used to develop the Planned Demand Resource quantities, including, but not limited to, discussion of:

- method(s) of achieving load reduction at customer site(s);
- equipment to be controlled or installed at customer site(s), if any;
- plan and ability to acquire customers;

- types of customer targeted;
- support of market potential and market share for the target customer base, with adjustments for Existing Demand Resource customers within this market and the potential for other Demand Resource Providers targeting the same customers; and
- assumptions regarding regulatory approval of program(s), if applicable.

(ii) Zone/sub-Zone information by end-use customer segment for all Nominated DR Values for which an end-use customer site is not identified, to include the number in each segment of end-use customers expected to be registered for the subject Delivery Year, the average Peak Load Contribution per end-use customer for such segment, and the average Nominated DR Value per customer for such segment. End-use customer segments may include residential, commercial, small industrial, medium industrial, and large industrial, as identified and defined in the PJM Manuals, provided that nothing herein or in the Manuals shall preclude the Provider from identifying more specific customer segments within the commercial and industrial categories, if known.

(iii) Information by end-use customer site to the extent required by subsection A-1(1)(c)(iv) or, if not required by such subsection, to the extent known at the time of the submittal of the Demand Resource Sell Offer Plan, to include: customer EDC account number (if known), customer name, customer premise address, Zone/sub-Zone in which the customer is located, end-use customer segment, current Peak Load Contribution value (or an estimate if actual value not known) and an estimate of expected Peak Load Contribution for the subject Delivery Year, and an estimated Nominated DR Value.

(iv) End-use customer site-specific information shall be required for any Zones or sub-Zones identified by PJM pursuant to this subsection for the portion, if any, of a Demand Resource Provider's intended offer in such Zones or sub-Zones that exceeds a Sell Offer threshold determined pursuant to this subsection, as any such excess quantity under such conditions should reflect Planned Demand Resources from end-use customer sites that the Provider has a high degree of certainty it will physically deliver for the subject Delivery Year. In accordance with the procedures in subsection A-1(3) below, PJM shall identify, as requiring site-specific information, all Zones and sub-Zones that comprise any LDA group (from a list of LDA groups stated in the PJM Manuals) in which [the quantity of cleared Demand Resources from the most recent Base Residual Auction] plus [the quantity of Demand Resources included in FRR Capacity Plans for the Delivery Year addressed by the most recent Base Residual Auction] in any Zone or sub-Zone of such LDA group exceeds the greater of:

- the maximum Demand Resources quantity registered with PJM for such Zone for any Delivery Year from the current (at time of plan submission) Delivery Year and the two preceding Delivery Years; and

- the potential Demand Resource quantity for such Zone estimated by PJM based on an independent published assessment of demand response potential that is reasonably applicable to such Zone, as identified in the PJM Manuals.

For each such Zone and sub-Zone, the Sell Offer threshold for each Demand Resource Provider shall be the higher of:

- the Demand Resource Provider's maximum Demand Resource quantity registered with PJM for such Zone/sub-Zone over the current Delivery Year (at the time of plan submission) and two preceding Delivery Years;

- the Demand Resource Provider's maximum for any single Delivery Year of [such provider's cleared Demand Resource quantity] plus [such provider's quantity of Demand Resources included in FRR Capacity Plans] from the three forward Delivery Years addressed by the three most recent Base Residual Auctions for such Zone/sub-Zone; and

- 10 MW.

(d) Schedule. The Demand Resource Provider shall provide an approximate timeline for procuring end-use customer sites as needed to physically deliver the total Nominated DR Value (for both Existing Demand Resources and Planned Demand Resources) by Zone/sub-Zone in the Demand Resource Sell Offer Plan. The Demand Resource Provider must specify the cumulative number of customers and the cumulative Nominated DR Value associated with each end-use customer segment within each Zone/sub-Zone that the Demand Resource Provider expects (at the time of plan submission) to have under contract as of June 1 each year between the time of the auction and the subject Delivery Year.

(e) Minimum Offer Price Rule for Demand Resources. The Demand Resource Provider shall certify whether or not the Existing Demand Resource end use customer site(s) and Planned Demand Resource is entitled to a State Subsidy. Such certifications shall be made separately for end-use customer locations that are entitled to receive State Subsidy and those that are not, in accordance with the procedures provided in the

PJM Manuals, to ensure the accurate application of the Minimum Offer Price Rules. Sell Offers for Demand Resources that are Capacity Resources with State Subsidy shall be offered separately for load-backed Demand Resources and generation-backed Demand Resources, unless the Capacity Market Seller for such Capacity Resource with State Subsidy elects the competitive exemption pursuant to Tariff, Attachment DD, section 5.14(h).

2. Demand Resource Officer Certification Form. Each Demand Resource Sell Offer Plan must include a Demand Resource Officer Certification, signed by an officer of the Demand Resource Provider that is duly authorized to provide such a certification, in the form shown in the PJM Manuals, which form shall include the following certifications:

(a) that the signing officer has reviewed the Demand Resource Sell Offer Plan and the information supplied to PJM in support of the Plan is true and correct as of the date of the certification; and

(b) that the Demand Resource Provider is submitting the Plan with the reasonable expectation, based upon its analyses as of the date of the certification, to physically deliver all megawatts that clear the RPM Auction through Demand Resource registrations by the specified Delivery Year.

As set forth in the form provided in the PJM Manuals, the certification shall specify that it does not in any way abridge, expand, or otherwise modify the current provisions of the PJM Tariff, Operating Agreement and/or RAA, or the Demand Resource Provider's rights and obligations thereunder, including the Demand Resource Provider's ability to adjust capacity obligations through participation in PJM incremental auctions and bilateral transactions.

3. Procedures. No later than December 1 prior to the Base Residual Auction for a Delivery Year, PJM shall post to the PJM website a list of Zones and sub-Zones, if any, for which end-use customer site-specific information shall be required under the conditions specified in subsection A-1(1)(c)(iv) above for all RPM Auctions conducted for such Delivery Year. Once so identified, a Zone or sub-Zone shall remain on the list for future Delivery Years until the threshold determined under subsection A-1(1)(c)(iv) above is not exceeded for three consecutive Delivery Years. No later than 30 days prior to the RPM Auction in which a Demand Resource Provider intends to offer a Demand Resource, the Demand Resource Provider shall submit to PJM a completed Demand Resource Sell Offer Plan template and a Demand Resource Officer Certification Form signed by a duly authorized officer of the Provider. PJM will review all submitted DR Sell Offer Plans. No later than 10 Business Days prior to the subject RPM Auction, PJM shall notify any Demand Resource Providers that have identified the same end-use customer site(s) in their respective DR Sell Offer Plans for the same Delivery Year. In such event, the MWs associated with such site(s) will not be approved for inclusion in a Sell Offer in an RPM Auction by

any of the Demand Resource Providers, unless a Demand Resource Provider provides a letter of support from the end-use customer indicating that it is likely to execute a contract with that Demand Resource Provider for the relevant Delivery Year, or provides other comparable evidence of likely commitment. Such letter of support or other supporting evidence must be provided to PJM no later than 7 Business Days prior to the subject RPM Auction. If an end-use customer provides letters of support for the same site for the same Delivery Year to multiple Demand Resource Providers, the MWs associated with such end-use customer site shall not be approved as a Demand Resource for any of the Demand Resource Providers. No later than 5 Business Days prior to the subject RPM Auction, PJM will notify each Demand Resource Provider of the approved Demand Resource quantity, by Zone/sub-Zone, that such Demand Resource Provider is permitted to offer into such RPM Auction.

B. The Unforced Capacity value of a Demand Resource will be determined as:

for the Delivery Years through May 31, 2018, or for FRR Capacity Plans for Delivery Years through May 31, 2019, the product of the Nominated Value of the Demand Resource, times the DR Factor, times the Forecast Pool Requirement, and for the 2018/2019 Delivery Year and subsequent Delivery Years, or for FRR Capacity Plans for the 2019/2020 Delivery Year and subsequent Delivery Years, the product of the Nominated Value of the Demand Resource times the Forecast Pool Requirement. Nominated Values shall be determined and reviewed in accordance with sections I and J, respectively, and the PJM Manuals. The DR Factor is a factor established by the PJM Board with the advice of the Members Committee to reflect the increase in the peak load carrying capability in the PJM Region due to Demand Resources. Peak load carrying capability is defined to be the peak load that the PJM Region is able to serve at the loss of load expectation defined in the Reliability Principles and Standards. The DR Factor is the increase in the peak load carrying capability in the PJM Region due to Demand Resources, divided by the total Nominated Value of Demand Resources in the PJM Region. The DR Factor will be determined using an analytical program that uses a probabilistic approach to determine reliability. The determination of the DR Factor will consider the reliability of Demand Resources, the number of interruptions, and the total amount of load reduction.

C. Demand Resources offered and cleared in a Base Residual or Incremental Auction shall receive the corresponding Capacity Resource Clearing Price as determined in such auction, in accordance with Tariff, Attachment DD. For Delivery Years beginning with the Delivery Year that commences on June 1, 2013, any Demand Resources located in a Zone with multiple LDAs shall receive the Capacity Resource Clearing Price applicable to the location of such resource within such Zone, as identified in such resource's offer. Further, the Curtailment Service Provider shall register its resource in the same location within the Zone as specified in its cleared sell offer, and shall be subject to deficiency charges under Tariff, Attachment DD to the extent it fails to provide the resource in such location consistent with its cleared offer.

D. The Party, Electric Distributor, or Curtailment Service Provider that establishes a contractual relationship (by contract or tariff rate) with a customer for load reductions is entitled to receive the compensation specified in section C for a committed Demand Resource, notwithstanding that such provider is not the customer's energy supplier.

E. Any Party hereto shall demonstrate that its Demand Resources performed during periods when load management procedures were invoked by the Office of the Interconnection. The Office of the Interconnection shall adopt and maintain rules and procedures for verifying the performance of such resources, as set forth in section K hereof and the PJM Manuals. In addition, committed Demand Resources that do not comply with the directions of the Office of the Interconnection to reduce load during an emergency shall be subject to the penalty charge set forth in Tariff, Attachment DD.

F. Parties may elect to place Demand Resources associated with Behind The Meter Generation under the direction of the Office of the Interconnection for a Delivery Year by submitting a Sell Offer for such resource (as Self Supply, or with an offer price) in the Base Residual Auction for such Delivery Year. This election shall remain in effect for the entirety of such Delivery Year. In the event such an election is made, such Behind The Meter Generation will not be netted from load for the purposes of calculating the Daily Unforced Capacity Obligations under this Agreement.

G. PJM measures Demand Resource Registrations in the following ways:

Firm Service Level (FSL) – Load management achieved by an end-use customer reducing its load to a pre-determined level (the Firm Service Level), upon notification from the Curtailment Service Provider's market operations center or its agent.

Guaranteed Load Drop (GLD) – Load management achieved by an end-use customer reducing its load by a pre-determined amount (the Guaranteed Load Drop), upon notification from the Curtailment Service Provider's market operations center or its agent. Typically, the load reduction is achieved through running customer-owned backup generators, or by shutting down process equipment.

H. Each Curtailment Service Provider must satisfy (or contract with another LSE, Curtailment Service Provider, or electric distribution company to provide) the following requirements:

- A point of contact with appropriate backup to ensure single call notification from PJM and timely execution of the notification process;

- Supplemental status reports, detailing Demand Resources available, as requested by PJM;

- Entry of customer-specific Demand Resource Registration information, for planning and verification purposes, into the designated PJM electronic system.

- Customer-specific compliance and verification information for each PJM-initiated Demand Resource event or Provider initiated test event, as well as aggregated Provider load drop data for Provider-initiated events, in accordance with established reporting guidelines.

- Load drop estimates for all Load Management events and test events, prepared in accordance with the PJM Manuals.

I. The Nominated Values (summer, winter or annual) for each Demand Resource Registration shall be determined consistent with the process described below.

The summer Nominated Value for Firm Service Level customer(s) on a registration will be based on the peak load contribution for the customer(s), as typically determined by the 5CP methodology utilized by the electric distribution company to determine ICAP obligation values. The summer Nominated Value for a registration shall equal the total peak load contribution for the customers on the registration minus the summer Firm Service Level multiplied by the loss factor. The winter Nominated Value for Firm Service Level customer(s) on a registration shall equal the total Winter Peak Load for customers on the registration multiplied by Zonal Winter Weather Adjustment Factor minus winter Firm Service level and then the result is multiplied by the loss factor. The annual Nominated Value for or Firm Service Level customer(s) on a registration shall equal the lesser of i) summer Nominated Value or ii) winter Nominated Value. Effective with the 2019/2020 Delivery Year, an annual Nominated Value for a registration is no longer calculated.

The summer Nominated Value for a Guaranteed Load Drop customer on a registrationshall equal the summer guaranteed load drop amount, adjusted for system losses and shall not exceed the customer's Peak Load Contribution, as established by the customer's contract with the Curtailment Service Provider. The winter Nominated Value for a Guaranteed Load Drop customer on a registration shall be the winter guaranteed load drop amount, adjusted for system losses, and shall not exceed the customer's Winter Peak Load multiplied by Zonal Winter Weather Adjustment Factor multiplied by the loss factor, as established by the customer's contract with the Curtailment Service Provider. The annual Nominated Value for a Guaranteed Load Drop customer on a registration shall be the lesser of the i) summer Nominated Value or ii) winter Nominated Value. Effective with the 2019/2020 Delivery Year, an annual Nominated Value for a registration is no longer calculated.

Customer-specific Demand Resource Registration information (EDC account number, peak load contribution, Winter Peak Load, notification period, etc.) will be entered into the designated PJM electronic system to establish nominated values. Each Demand Resource Registration should be linked to a Demand Resource. Additional data may be required, as defined in sections J and K and the PJM Manuals.

J. Nominated Values shall be reviewed based on documentation of customer-specific data and Demand Resource Registration information, to verify the amount of load management available and to set a summer, winter, or annual Nominated Value. Data is provided by both the zone EDC and the Curtailment Service Provider in the designated PJM electronic system, and must include the EDC meter number or other unique customer identifier, Peak Load Contribution (5CP), Winter Peak Load, contract firm service level or guaranteed load drop values, applicable loss factor, zone/area location of the load drop, number of active participants, etc. Such data must be uploaded and approved prior to the first day of the Delivery Year for which such Demand Resource Registration is effective. Curtailment Service Providers must provide this information concurrently to host EDCs.

For Firm Service Level and Guaranteed Load Drop customers, the 5CP values, for the zone and affected customers, will be adjusted to reflect an "unrestricted" peak for a zone, based on information provided by the Curtailment Service Provider. Load drop levels shall be estimated in accordance with guidelines in the PJM Manuals.

The daily Nominated Value for the Delivery Year for a Limited Demand Resource, Extended Summer Demand Resource, Base Capacity Demand Resource, and Annual Demand Resource without a Capacity Performance commitment shall equal the sum of the summer Nominated Values of the registrations linked to such Demand Resource. For the 2017/2018 and 2018/2019 Delivery Years, the daily Nominated Value for the Delivery Year for an Annual Demand Resource with a Capacity Performance commitment shall equal the sum of the annual Nominated Values of the registrations linked to such Demand Resource. For the 2019/2020 Delivery Year, the daily Nominated Value for the Delivery Year for an Annual Demand Resource with a Capacity Performance commitment shall equal the lesser of (i) the sum of the summer Nominated Values of the registrations linked to such Demand Resource or (ii) the sum of the winter Nominated Values of the registrations linked to such Demand Resource. Effective with the 2020/2021 Delivery Year, the daily Nominated Value of a Demand Resource with a Capacity Performance commitment (which may consist of an Annual Demand Resource with a Capacity Performance commitment and/or Summer Period Demand Resource with a Capacity Performance commitment) shall equal the sum of the summer Nominated Values of the registrations linked to such Demand Resource for the summer period of June through October and May of the Delivery Year, and shall equal the lesser of (i) the sum of the summer Nominated Values of the registrations linked to such Demand Resource or (ii) the sum of the winter Nominated Values of the registrations linked to such Demand Resource for the non-summer period of November through April of the Delivery Year.

K. Compliance is the process utilized to review Provider performance during PJM-initiated Load Management events and Curtailment Service Provider initiated tests. Compliance will be established for each Provider on an event specific basis for the Curtailment Service Provider's Demand Resource Registrations dispatched by the Office of the Interconnection during such event. PJM will establish and communicate reasonable deadlines for the timely submittal of event data to expedite compliance reviews. Compliance reviews will be completed as soon after the event as possible, with the expectation that reviews of a single event will be completed within two months of the end of the month in which the event took place. Curtailment Service Providers are responsible for the submittal of compliance information to PJM for each PJM-initiated event and Curtailment Service Provider initiated test during the compliance period.

Compliance is measured for Market Participant Bonus Performance, as applicable, and Non-Performance Charges. Non-Performance Charges are assessed for the defined obligation period of each Demand Resource as defined in RAA, Article 1, subject to the following requirements:

Compliance is checked on an individual customer basis for Firm Service Level, by comparing actual load during the event to the firm service level. Current load for a statistical sample of end-use customers may be used for compliance for residential non-interval metered registrations in accordance with the PJM Manuals and subject to PJM approval. Curtailment Service Providers must submit actual customer load levels (for the event period) for the compliance report. Compliance for FSL will be based on:

> Summer (June through October and the following May of a Delivery Year)- End use customer's current Delivery Year peak load contribution ("PLC") minus the metered load ("Load") multiplied by the loss factor ("LF"). The calculation is represented by:
>
> (PLC) - (Load *LF)
>
> Winter (November through April of a Delivery Year)– End use customer's Winter Peak Load ("WPL") multiplied by Zonal Winter Weather Adjustment Factor ("ZWWAF") multiplied by LF, minus the metered load ("Load") multiplied by the LF. The calculation is represented by:
>
> (WPL * ZWWAF * LF) – (Load * LF)

Compliance is checked on an individual customer basis for Guaranteed Load Drop. Current load for a statistical sample of end-use customers may be used for compliance for residential non-interval metered registrations in accordance with the PJM Manuals and subject to PJM approval. Guaranteed Load Drop compliance will be based on:

(i) the lesser of (a) comparison load used to best represent what the load would have been if PJM did not declare a Load Management Event or the CSP did not initiate a test as outlined in the PJM Manuals, minus the Load and then multiplied by the LF, or (b) For a summer event, the PLC minus the Load multiplied by the LF. A summer load reduction will only be recognized for capacity compliance if the Load multiplied by the LF is less than the PLC. For a non-summer event, the WPL multiplied the ZWWAF multiplied by LF, minus the Load multiplied by the LF. A non-summer load reduction will only be recognized for capacity compliance if the Load multiplied by the LF is less than the WPL multiplied by the ZWWAF multiplied by LF.

(ii) Curtailment Service Providers must submit actual loads and comparison loads for all hours during the day of the Load Management Event or the Load Management performance test, and for all hours during any other days as required by the Office of the Interconnection to calculate the load reduction. Comparison loads must be developed from the guidelines in the PJM Manuals, and note which method was employed.

(iii) Methodologies for establishing comparison load for Guaranteed Load Drop end-use customers are described in greater detail in Manual M-19, PJM Manual for Load Forecasting and Analysis, at Attachment A: Load Drop Estimate Guidelines.

Load reduction compliance is averaged over the Load Management Event for a Demand Resource Registration linked to a Limited Demand Resource, Extended Summer Demand Resource, or Annual Demand Resource without a Capacity Performance commitment or determined on an hourly basis for a Demand Resource Registration linked to a Base Capacity Demand Resource or Annual Demand Resource with a Capacity Performance commitment, for each FSL and GLD customer dispatched by the Office of the Interconnection for at least 30 minutes of the clock hour (i.e., "partial dispatch compliance hour"). The registered capacity commitment for a Demand Resource Registration without a Base or Capacity Performance commitment for the partial dispatch compliance hour will be prorated based on the number of minutes dispatched during the clock hour and as defined in the Manuals. Curtailment Service Provider may submit 1 minute load data for use in capacity compliance calculations for partial dispatch compliance hours subject to PJM approval and in accordance with the PJM Manuals where: (a) metering meets all Tariff and Manual requirements, (b) 1 minute load data shall be submitted to PJM for all locations on the registration, and (c) 1 minute load data measures energy consumption over the minute. The registered capacity commitment for a Demand Resource Registration with a Base or Capacity Performance commitment is not prorated based on the number of minutes dispatched during the clock hours. The actual hourly load reduction for the hour ending that includes a Performance Assessment Interval(s) is flat-profiled over the set of dispatch intervals in the hour in accordance with the PJM Manuals.

A Demand Resource Registration may not reduce their load below zero (i.e., export energy into the system). No compliance credit will be given for an incremental load drop below zero.

Compliance will be totaled over all dispatched registrations for FSL and GLD customers linked to a committed Limited Demand Resource, Extended Summer Demand Resource, and Annual Demand Resource without a Capacity Performance commitment to determine a net compliance position for the event for each Provider by Compliance Aggregation Area and such net compliance position shall be allocated to the underlying registrations, in accordance with PJM Manuals. Load Management Event deficiencies shall be as further determined in accordance with Tariff, Attachment DD, section 11 and PJM Manuals.

For a Performance Assessment Interval, compliance will be totaled over all dispatched registrations for FSL and GLD customers linked to a Provider's Base Capacity Demand Resource or to an Annual Demand Resource with a Capacity Performance commitment to determine the Actual Performance for such Demand Resource in accordance with Tariff, Attachment DD, section 10A, and PJM Manuals. The Expected Performance for such Demand Resource shall be equal to the Provider's committed capacity on the Demand Resource, adjusted to account for any linked registrations that were not dispatched by PJM. A Provider's Demand Resources' initial Performance Shortfalls shall be netted for all the seller's Demand Resources in the Emergency Action Area to determine a net Emergency Action Area Performance Shortfall which is then allocated to the Capacity Market Seller's Demand Resources in accordance with Tariff, Attachment DD, section 10A, and PJM Manuals.

L. Energy Efficiency Resources

1. An Energy Efficiency Resource is a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during peak summer and winter periods as described herein) reduction in electric energy consumption at the End-Use Customer's retail site that is not reflected in the peak load forecast prepared for the Delivery Year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.

2. An Energy Efficiency Resource may be offered as a Capacity Resource in the Base Residual or Incremental Auctions for any Delivery Year beginning on or after June 1, 2011. No later than 30 days prior to the auction in which the resource is to be offered, the Capacity Market Seller shall submit to the Office of the Interconnection a notice of intent to offer the resource into such auction and a measurement and verification plan. The notice of intent shall include all pertinent project design data, including but not limited to the peak-load contribution of affected customers, a full description of the equipment, device, system or process intended to achieve the load reduction, the load reduction pattern, the project location, the project development timeline, and any other relevant data. Such notice also shall state the seller's proposed Nominated Energy Efficiency Value.

   - For Delivery Years through May 31, 2018 for all Energy Efficiency Resources not committed as a Capacity Performance Resource, the seller's proposed Nominated Energy Efficiency Value shall be the expected average load reduction between the hour ending 15:00 EPT and the hour ending 18:00 EPT during all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday;

   - For the 2018/2019 and 2019/2020 Delivery Years, the seller's proposed Nominated Energy Efficiency Value for any Base Capacity Energy Efficiency

Resource shall be the expected average load reduction between the hour ending 15:00 EPT and the hour ending 18:00 EPT during all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday; and

- For the 2018/2019 Delivery Year and subsequent Delivery Years and for any Annual Energy Efficiency Resource committed as a Capacity Performance Resource for the 2016/2017 and 2017/2018 Delivery Years, the seller's proposed Nominated Energy Efficiency Value for any Annual Energy Efficiency Resources, shall be the expected average load reduction, for all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday, between the hour ending 15:00 EPT and the hour ending 18:00 EPT. In addition, the expected average load reduction for all days from January 1 through February 28, inclusive, of such Delivery Year that is not a weekend or federal holiday, between the hour ending 8:00 EPT and the hour ending 9:00 EPT and between the hour ending 19:00 EPT and the hour ending 20:00 EPT shall not be less than the Nominated Energy Efficiency Value; and

- For the 2020/2021 Delivery Year and subsequent Delivery Years, the seller's proposed Nominated Energy Efficiency Value for any Summer-Period Energy Efficiency Resource shall be the expected average load reduction between the hour ending 15:00 EPT and the hour ending 18:00 EPT during all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday.

The measurement and verification plan shall describe the methods and procedures, consistent with the PJM Manuals, for determining the amount of the load reduction and confirming that such reduction is achieved. The Office of the Interconnection shall determine, upon review of such notice, the Nominated Energy Efficiency Value that may be offered in the Reliability Pricing Model Auction.

3. An Energy Efficiency Resource may be offered with a price offer or as Self-Supply. If an Energy Efficiency Resource clears the auction, it shall receive the applicable Capacity Resource Clearing Price, subject to section 5 below. A Capacity Market Seller offering an Energy Efficiency Resource must comply with all applicable credit requirements as set forth in Tariff, Attachment Q. For Delivery Years through May 31, 2018, or for FRR Capacity Plans for Delivery Years through May 31, 2019, the Unforced Capacity value of an Energy Efficiency Resource offered into an RPM Auction shall be the Nominated Energy Efficiency value times the DR Factor and the Forecast Pool Requirement. For the 2018/2019 Delivery Year and subsequent Delivery Years, or for FRR Capacity Plans for the 2019/2020 Delivery Year and subsequent Delivery Years, the Unforced Capacity value of an Energy Efficiency Resource offered into an RPM

Auction shall be the Nominated Energy Efficiency Value times the Forecast Pool Requirement.

4. An Energy Efficiency Resource that clears an auction for a Delivery Year may be offered in auctions for up to three additional consecutive Delivery Years, but shall not be assured of clearing in any such auction; provided, however, an Energy Efficiency Resource may not be offered for any Delivery Year in which any part of the peak season is beyond the expected life of the equipment, device, system, or process providing the expected load reduction; and provided further that a Capacity Market Seller that offers and clears an Energy Efficiency Resource in a BRA may elect a New Entry Price Adjustment on the same terms as set forth in Tariff, Attachment DD, section 5.14(c).

5. For every Energy Efficiency Resource clearing an RPM Auction for a Delivery Year, the Capacity Market Seller shall submit to the Office of the Interconnection, by no later than 30 days prior to each Auction an updated project status and measurement and verification plan subject to the criteria set forth in the PJM Manuals.

6. For every Energy Efficiency Resource clearing an RPM Auction for a Delivery Year, the Capacity Market Seller shall submit to the Office of the Interconnection, by no later than the start of such Delivery Year, an updated project status and detailed measurement and verification data meeting the standards for precision and accuracy set forth in the PJM Manuals. The final value of the Energy Efficiency Resource during such Delivery Year shall be as determined by the Office of the Interconnection based on the submitted data.

7. The Office of the Interconnection may audit, at the Capacity Market Seller's expense, any Energy Efficiency Resource committed to the PJM Region. The audit may be conducted any time including the Performance Hours of the Delivery Year.

8. For Incremental Auctions conducted for the 2019/2020 and 2020/2021 Delivery Years, and for RPM Auctions for the 2021/2022 Delivery Year and subsequent Delivery Years, if a Relevant Electric Retail Regulatory Authority receives FERC authorization to qualify or prohibit Energy Efficiency Resource participation in a specific area(s) of the PJM Region, the following process applies:

(a) The Office of the Interconnection will publicly post a reference to the FERC authorization of a Relevant Electric Retail Regulatory Authority order, ordinance or resolution that qualifies or prohibits Energy Efficiency Resource participation, the applicable electric distribution company(ies), and the applicable auction(s) and/or Delivery Year(s).

(b) A Capacity Market Seller that intends to offer or certify Energy Efficiency Resources must identify and itemize all resources that are located in the jurisdiction of a Relevant Electric Retail Regulatory Authority authorized by FERC to qualify or prohibit Energy Efficiency Resource participation within the Zone or LDA, as required, and those outside of the area but within the Zone or LDA, as required.

(c) A Capacity Market Seller that intends to offer or certify Energy Efficiency Resources must identify and itemize all Energy Efficiency Resources to be offered as part of its Energy Efficiency measurement and verification plan and certified post-installation measurement and verification report. The Office of Interconnection will provide a list to the relevant electric distribution company for the specific area(s) to review for compliance with the Relevant Electric Retail Regulatory Authority of Capacity Market Sellers that are:

(i) offering Energy Efficiency Resources in an RPM Auction within two (2) Business Days after the deadline for submitting an energy efficiency measurement and verification plan for such RPM Auction; and

(ii) certifying Energy Efficiency Resources with a Delivery Year post-installation measurement and verification report, within two (2) Business Days of receipt of such Delivery Year post-installation measurement and verification report.The relevant electric distribution company for the specific area(s) shall review for compliance with rules from a Relevant Electric Retail Regulatory Authority authorized by FERC to qualify or prohibit Energy Efficiency Resource.

(d) The relevant electric distribution company for the specific area(s) shall review for compliance with rules from a Relevant Electric Retail Regulatory Authority authorized by FERC to qualify or prohibit Energy Efficiency Resource participation and provide a response to the Office of the Interconnection within five (5) Business Days after receiving the list of Capacity Market Sellers offering Energy Efficiency Resources. The Office of the Interconnection will not allow a Capacity Market Seller to offer or certify Energy Efficiency Resources if an electric distribution company denies such Capacity Market Seller to deliver Energy Efficiency Resources in compliance with rules of a Relevant Electric Retail Regulatory Authority authorized by FERC to qualify or prohibit Energy Efficiency Resource participation.

(9) For Incremental Auctions that will be conducted for the 2019/2020 and 2020/2021 Delivery Years, and for RPM Auctions for the 2021/2022 Delivery

Year and subsequent Delivery Years, a Capacity Market Seller of Energy Efficiency Resources that cannot satisfy its RPM obligations in any Delivery Year due to the prohibition of participation by a Relevant Electric Retail Regulatory Authority authorized by FERC to prohibit participation of such resources may be relieved of its Capacity Resource Deficiency Charge by notifying the Office of the Interconnection by no later than seven (7) calendar days prior to the posting of the planning parameters for the Third Incremental Auction of that Delivery Year. After providing such notice, the affected Capacity Market Seller may elect to be relieved of its RPM commitment, and shall not be required to obtain replacement capacity for the resource, and no charges shall be assessed by the Office of the Interconnection for the Capacity Market Seller's deficiency in satisfying its RPM obligation for the resource for such Delivery Year. In such case, however, the Capacity Market Seller shall not be entitled to, nor be paid, any RPM revenues for such resource for that Delivery Year. The Office of the Interconnection will apply corresponding adjustments to the quantity of Buy Bids or Sell Offers in the Incremental Auctions for such Delivery Years in accordance with Tariff, Attachment DD, sections 5.12(b)(ii) and 5.12(b)(iii).

Section of the
PJM Reliability Assurance Agreement

(Clean Format)

SCHEDULE 6

PROCEDURES FOR DEMAND RESOURCES AND ENERGY EFFICIENCY

A. Parties can partially or wholly offset the amounts payable for the Locational Reliability Charge with Demand Resources that are operated under the direction of the Office of the Interconnection. FRR Entities may reduce their capacity obligations with Demand Resources that are operated under the direction of the Office of the Interconnection and detailed in such entity's FRR Capacity Plan. Demand Resources qualifying under the criteria set forth below may be offered for sale or designated as Self-Supply in the Base Residual Auction, included in an FRR Capacity Plan, or offered for sale in any Incremental Auction, for any Delivery Year for which such resource qualifies. Qualified Demand Resources generally fall in one of two categories, i.e., Guaranteed Load Drop or Firm Service Level, as further specified in section G below and the PJM Manuals. Qualified Demand Resources may be provided by a Curtailment Service Provider, notwithstanding that such Curtailment Service Provider is not a Party to this Agreement. Such Curtailment Service Providers must satisfy the requirements hereof and the PJM Manuals.

1. A Party must formally notify, in accordance with the requirements of the PJM Manuals and section F hereof, as applicable, the Office of the Interconnection of the Demand Resource Registration that it is placing under the direction of the Office of the Interconnection. A Party must further notify the Office of the Interconnection whether the Demand Resource Registration is linked to a Limited Demand Resource, an Extended Summer Demand Resource, a Base Capacity Demand Resource, a Summer-Period Demand Resource or an Annual Demand Resource.

2. A Demand Resource Registration must achieve its full load reduction within the following time period:

(a) For the 2015/2016 Delivery Year and subsequent Delivery Years, a Demand Resource Registration must be able to fully respond to a Load Management Event within 30 minutes of notification from the Office of the Interconnection. This default 30 minute prior notification shall apply unless a Curtailment Service Provider obtains an exception from the Office of the Interconnection due to physical operational limitations that prevent the Demand Resource Registration from reducing load within that timeframe. In such case, the Curtailment Service Provider shall submit a request for an exception to the 30 minute prior notification requirement to the Office of the Interconnection, at the time the Registration Form for that Demand Resource Registration is submitted in accordance with Tariff, Attachment K-Appendix. The only alternative notification times that the Office of Interconnection will permit, upon approval of an exception request, are 60 minutes and 120 minutes prior to a Load Management Event. The Curtailment Service Provider shall indicate in writing, in the appropriate application, that it seeks an exception to permit a prior notification time of 60 minutes or 120 minutes, and the reason(s) for the requested exception. A Curtailment Service

Provider shall not submit a request for an exception to the default 30 minute notification period unless it has done its due diligence to confirm that the Demand Resource Registration is physically incapable of responding within that timeframe based on one or more of the reasons set forth below and as may be further defined in the PJM Manuals and has obtained detailed data and documentation to support this determination.

In order to establish that a Demand Resource Registration is reasonably expected to be physically unable to reduce load in that timeframe, the Curtailment Service Provider that submitted the Demand Resource Registration must demonstrate that:

(i) The manufacturing processes for the Demand Resource Registration require gradual reduction to avoid damaging major industrial equipment used in the manufacturing process, or damage to the product generated or feedstock used in the manufacturing process;

(ii) Transfer of load to back-up generation requires time-intensive manual process taking more than 30 minutes;

(iii) On-site safety concerns prevent location from implementing reduction plan in less than 30 minutes; or,

(iv) The Demand Resource Registration is comprised of mass market residential customers or Small Commercial Customers which collectively cannot be notified of a Load Management Event within a 30-minute timeframe due to unavoidable communications latency, in which case the requested notification time shall be no longer than 120 minutes.

The Office of the Interconnection may request data and documentation from the Curtailment Service Provider and such Curtailment Service Provider shall provide to the Office of the Interconnection within three (3) Business Days of a request therefor, a copy of all of the data and documentation supporting the exception request. Failure to provide a timely response to such request shall cause the exception to terminate the following Operating Day.

At its sole option and discretion, the Office of the Interconnection may review the data and documentation provided by the Curtailment Service Provider to determine if the Demand Resource Registration has met one or more of the criteria above. The Office of the Interconnection will notify the Curtailment Service Provider in writing of its determination by no later than ten (10) Business Days after receipt of the data and documentation.

The Curtailment Service Provider shall provide written notification to the Office of the Interconnection of a material change to the facts that supported its exception request within three (3) Business Days of becoming aware of such material change in facts, and, if the Office of Interconnection determines that the physical limitation criteria above are no longer being met, the Demand Resource Registration shall be subject to the default notification period of 30 minutes immediately upon such determination.

3. The initiation of load reduction, upon the request of the Office of the Interconnection, must be within the authority of the dispatchers of the Party. No additional approvals should be required.

4. The initiation of load reduction upon the request of the Office of the Interconnection is considered a pre-emergency or emergency action and must be implementable prior to a voltage reduction.

5. A Curtailment Service Provider intending to offer for sale or designate for self-supply, a Demand Resource in any RPM Auction, or intending to include a Demand Resource in any FRR Capacity Plan must demonstrate, to PJM's satisfaction, that such resource shall have the capability to provide a reduction in demand, or otherwise control load, on or before the start of the Delivery Year for which such resource is committed. As part of such demonstration, each such Curtailment Service Provider shall submit a Demand Resource Sell Offer Plan in accordance with the standards and procedures set forth in RAA, Schedule 6, section A-1; RAA, Schedule 8.1 (as to FRR Capacity Plans) and the PJM Manuals, no later than 30 days prior to, as applicable, the RPM Auction in which such resource is to be offered, or the deadline for submission of the FRR Capacity Plan in which such resource is to be included. PJM may verify the Curtailment Service Provider's adherence to the Demand Resource Sell Offer Plan at any time. A Curtailment Service Provider with a PJM-approved Demand Resource Sell Offer Plan will be permitted to offer up to the approved Demand Resource quantity into the subject RPM Auction or include such resource in its FRR Capacity Plan.

6. Selection of a Demand Resource in an RPM Auction results in commitment of capacity to the PJM Region. Demand Resources that are so committed must be linked to registrations participating in the Full Program Option or Capacity Only Option of the Emergency Load Response and Pre-Emergency Load Response Program and thus available for dispatch during PJM-declared pre-emergency events and emergency events.

A-1. A Demand Resource Sell Offer Plan shall consist of a completed template document in the form posted on the PJM website, requiring the information set forth below and in the PJM Manuals, and a Demand Resource Officer Certification Form signed by an officer of the Demand Resource Provider that is duly authorized to provide such a certification. The Demand Resource Sell Offer Plan must provide information that supports the Demand Resource Provider's intended Demand Resource Sell Offers and demonstrates that the Demand Resources are being offered with the intention that the MW quantity that clears the auction is reasonably expected to be physically delivered through Demand Resource registrations for the relevant Delivery Year. The Demand Resource Sell Offer Plan shall include all Existing Demand Resources and all Planned Demand Resources that the Demand Resource Provider intends to offer into an RPM Auction or include in an FRR Capacity Plan.

> 1. Demand Resource Sell Offer Plan Template. The Demand Resource Sell Offer Plan template, in the form provided on the PJM website, shall require the

Demand Resource Provider to provide the following information and such other information as specified in the PJM Manuals:

(a) Summary Information. The completed template shall include the Demand Resource Provider's company name, contact information, and the Nominated DR Value in ICAP MWs by Zone/sub-Zone that the Demand Resource Provider intends to offer, stated separately for Existing Demand Resources and Planned Demand Resources. The total Nominated DR Value in MWs for each Zone/sub-Zone shall be the sum of the Nominated DR Value of Existing Demand Resources and the Nominated DR Value of Planned Demand Resources, and shall be the maximum MW amount the Provider intends to offer in the RPM Auction for the indicated Zone/sub-Zone, provided that nothing herein shall preclude the Demand Resource Provider from offering in the auction a lesser amount than the total Nominated DR Value shown in its Demand Resource Sell Offer Plan.

(b) Existing Demand Resources. The Demand Resource Provider shall identify all Existing Demand Resources by identifying end-use customer sites that are currently registered with PJM (even if not registered by such Demand Resource Provider) and that the Demand Resource Provider reasonably expects to have under a contract to reduce load based on PJM dispatch instructions by the start of the auction Delivery Year.

(c) Planned Demand Resources. The Demand Resource Provider shall provide the details of, and key assumptions underlying, the Planned Demand Resource quantities (i.e., all Demand Resource quantities in excess of Existing Demand Resource quantities) contained in the Demand Resource Sell Offer Plan, including:

(i) key program attributes and assumptions used to develop the Planned Demand Resource quantities, including, but not limited to, discussion of:

- method(s) of achieving load reduction at customer site(s);
- equipment to be controlled or installed at customer site(s), if any;
- plan and ability to acquire customers;
- types of customer targeted;
- support of market potential and market share for the target customer base, with adjustments for Existing Demand Resource customers within this market and the potential for other Demand Resource Providers targeting the same customers; and
- assumptions regarding regulatory approval of program(s), if applicable.

(ii) Zone/sub-Zone information by end-use customer segment for all Nominated DR Values for which an end-use customer site is not identified, to include the number in each segment of end-use customers expected to be registered for the subject Delivery Year, the average Peak Load Contribution per end-use customer for such segment, and the average Nominated DR Value per customer for such segment. End-use customer segments may include residential, commercial, small industrial, medium industrial, and large industrial, as identified and defined in the PJM Manuals, provided that nothing herein or in the Manuals shall preclude the Provider from identifying more specific customer segments within the commercial and industrial categories, if known.

(iii) Information by end-use customer site to the extent required by subsection A-1(1)(c)(iv) or, if not required by such subsection, to the extent known at the time of the submittal of the Demand Resource Sell Offer Plan, to include: customer EDC account number (if known), customer name, customer premise address, Zone/sub-Zone in which the customer is located, end-use customer segment, current Peak Load Contribution value (or an estimate if actual value not known) and an estimate of expected Peak Load Contribution for the subject Delivery Year, and an estimated Nominated DR Value.

(iv) End-use customer site-specific information shall be required for any Zones or sub-Zones identified by PJM pursuant to this subsection for the portion, if any, of a Demand Resource Provider's intended offer in such Zones or sub-Zones that exceeds a Sell Offer threshold determined pursuant to this subsection, as any such excess quantity under such conditions should reflect Planned Demand Resources from end-use customer sites that the Provider has a high degree of certainty it will physically deliver for the subject Delivery Year. In accordance with the procedures in subsection A-1(3) below, PJM shall identify, as requiring site-specific information, all Zones and sub-Zones that comprise any LDA group (from a list of LDA groups stated in the PJM Manuals) in which [the quantity of cleared Demand Resources from the most recent Base Residual Auction] plus [the quantity of Demand Resources included in FRR Capacity Plans for the Delivery Year addressed by the most recent Base Residual Auction] in any Zone or sub-Zone of such LDA group exceeds the greater of:

- the maximum Demand Resources quantity registered with PJM for such Zone for any Delivery Year from the current (at time of plan submission) Delivery Year and the two preceding Delivery Years; and

- the potential Demand Resource quantity for such Zone estimated by PJM based on an independent published assessment of demand response potential that is reasonably applicable to such Zone, as identified in the PJM Manuals.

For each such Zone and sub-Zone, the Sell Offer threshold for each Demand Resource Provider shall be the higher of:

- the Demand Resource Provider's maximum Demand Resource quantity registered with PJM for such Zone/sub-Zone over the current Delivery Year (at the time of plan submission) and two preceding Delivery Years;
- the Demand Resource Provider's maximum for any single Delivery Year of [such provider's cleared Demand Resource quantity] plus [such provider's quantity of Demand Resources included in FRR Capacity Plans] from the three forward Delivery Years addressed by the three most recent Base Residual Auctions for such Zone/sub-Zone; and
- 10 MW.

(d) Schedule. The Demand Resource Provider shall provide an approximate timeline for procuring end-use customer sites as needed to physically deliver the total Nominated DR Value (for both Existing Demand Resources and Planned Demand Resources) by Zone/sub-Zone in the Demand Resource Sell Offer Plan. The Demand Resource Provider must specify the cumulative number of customers and the cumulative Nominated DR Value associated with each end-use customer segment within each Zone/sub-Zone that the Demand Resource Provider expects (at the time of plan submission) to have under contract as of June 1 each year between the time of the auction and the subject Delivery Year.

(e) Minimum Offer Price Rule for Demand Resources. The Demand Resource Provider shall certify whether or not the Existing Demand Resource end use customer site(s) and Planned Demand Resource is entitled to a State Subsidy. Such certifications shall be made separately for end-use customer locations that are entitled to receive State Subsidy and those that are not, in accordance with the procedures provided in the PJM Manuals, to ensure the accurate application of the Minimum Offer Price Rules. Sell Offers for Demand Resources that are Capacity Resources with State Subsidy shall be offered separately for load-backed Demand Resources and generation-backed Demand Resources, unless the Capacity Market Seller for such Capacity Resource with State Subsidy elects the competitive exemption pursuant to Tariff, Attachment DD, section 5.14(h).

2. Demand Resource Officer Certification Form. Each Demand Resource Sell Offer Plan must include a Demand Resource Officer Certification, signed by an officer of the Demand Resource Provider that is duly authorized to provide such a certification, in the form shown in the PJM Manuals, which form shall include the following certifications:

(a) that the signing officer has reviewed the Demand Resource Sell Offer Plan and the information supplied to PJM in support of the Plan is true and correct as of the date of the certification; and

(b) that the Demand Resource Provider is submitting the Plan with the reasonable expectation, based upon its analyses as of the date of the certification, to physically deliver all megawatts that clear the RPM Auction through Demand Resource registrations by the specified Delivery Year.

As set forth in the form provided in the PJM Manuals, the certification shall specify that it does not in any way abridge, expand, or otherwise modify the current provisions of the PJM Tariff, Operating Agreement and/or RAA, or the Demand Resource Provider's rights and obligations thereunder, including the Demand Resource Provider's ability to adjust capacity obligations through participation in PJM incremental auctions and bilateral transactions.

3. Procedures. No later than December 1 prior to the Base Residual Auction for a Delivery Year, PJM shall post to the PJM website a list of Zones and sub-Zones, if any, for which end-use customer site-specific information shall be required under the conditions specified in subsection A-1(1)(c)(iv) above for all RPM Auctions conducted for such Delivery Year. Once so identified, a Zone or sub-Zone shall remain on the list for future Delivery Years until the threshold determined under subsection A-1(1)(c)(iv) above is not exceeded for three consecutive Delivery Years. No later than 30 days prior to the RPM Auction in which a Demand Resource Provider intends to offer a Demand Resource, the Demand Resource Provider shall submit to PJM a completed Demand Resource Sell Offer Plan template and a Demand Resource Officer Certification Form signed by a duly authorized officer of the Provider. PJM will review all submitted DR Sell Offer Plans. No later than 10 Business Days prior to the subject RPM Auction, PJM shall notify any Demand Resource Providers that have identified the same end-use customer site(s) in their respective DR Sell Offer Plans for the same Delivery Year. In such event, the MWs associated with such site(s) will not be approved for inclusion in a Sell Offer in an RPM Auction by any of the Demand Resource Providers, unless a Demand Resource Provider provides a letter of support from the end-use customer indicating that it is likely to execute a contract with that Demand Resource Provider for the relevant Delivery Year, or provides other comparable evidence of likely commitment. Such letter of support or other supporting evidence must be provided to PJM no later than 7 Business Days prior to the subject RPM Auction. If an end-use customer

provides letters of support for the same site for the same Delivery Year to multiple Demand Resource Providers, the MWs associated with such end-use customer site shall not be approved as a Demand Resource for any of the Demand Resource Providers. No later than 5 Business Days prior to the subject RPM Auction, PJM will notify each Demand Resource Provider of the approved Demand Resource quantity, by Zone/sub-Zone, that such Demand Resource Provider is permitted to offer into such RPM Auction.

B. The Unforced Capacity value of a Demand Resource will be determined as:

for the Delivery Years through May 31, 2018, or for FRR Capacity Plans for Delivery Years through May 31, 2019, the product of the Nominated Value of the Demand Resource, times the DR Factor, times the Forecast Pool Requirement, and for the 2018/2019 Delivery Year and subsequent Delivery Years, or for FRR Capacity Plans for the 2019/2020 Delivery Year and subsequent Delivery Years, the product of the Nominated Value of the Demand Resource times the Forecast Pool Requirement. Nominated Values shall be determined and reviewed in accordance with sections I and J, respectively, and the PJM Manuals. The DR Factor is a factor established by the PJM Board with the advice of the Members Committee to reflect the increase in the peak load carrying capability in the PJM Region due to Demand Resources. Peak load carrying capability is defined to be the peak load that the PJM Region is able to serve at the loss of load expectation defined in the Reliability Principles and Standards. The DR Factor is the increase in the peak load carrying capability in the PJM Region due to Demand Resources, divided by the total Nominated Value of Demand Resources in the PJM Region. The DR Factor will be determined using an analytical program that uses a probabilistic approach to determine reliability. The determination of the DR Factor will consider the reliability of Demand Resources, the number of interruptions, and the total amount of load reduction.

C. Demand Resources offered and cleared in a Base Residual or Incremental Auction shall receive the corresponding Capacity Resource Clearing Price as determined in such auction, in accordance with Tariff, Attachment DD. For Delivery Years beginning with the Delivery Year that commences on June 1, 2013, any Demand Resources located in a Zone with multiple LDAs shall receive the Capacity Resource Clearing Price applicable to the location of such resource within such Zone, as identified in such resource's offer. Further, the Curtailment Service Provider shall register its resource in the same location within the Zone as specified in its cleared sell offer, and shall be subject to deficiency charges under Tariff, Attachment DD to the extent it fails to provide the resource in such location consistent with its cleared offer.

D. The Party, Electric Distributor, or Curtailment Service Provider that establishes a contractual relationship (by contract or tariff rate) with a customer for load reductions is entitled to receive the compensation specified in section C for a committed Demand Resource, notwithstanding that such provider is not the customer's energy supplier.

E. Any Party hereto shall demonstrate that its Demand Resources performed during periods when load management procedures were invoked by the Office of the Interconnection. The Office of the Interconnection shall adopt and maintain rules and procedures for verifying the performance of such resources, as set forth in section K hereof and the PJM Manuals. In addition, committed Demand Resources that do not comply with the directions of the Office of the Interconnection to reduce load during an emergency shall be subject to the penalty charge set forth in Tariff, Attachment DD.

F. Parties may elect to place Demand Resources associated with Behind The Meter Generation under the direction of the Office of the Interconnection for a Delivery Year by submitting a Sell Offer for such resource (as Self Supply, or with an offer price) in the Base Residual Auction for such Delivery Year. This election shall remain in effect for the entirety of such Delivery Year. In the event such an election is made, such Behind The Meter Generation will not be netted from load for the purposes of calculating the Daily Unforced Capacity Obligations under this Agreement.

G. PJM measures Demand Resource Registrations in the following ways:

Firm Service Level (FSL) – Load management achieved by an end-use customer reducing its load to a pre-determined level (the Firm Service Level), upon notification from the Curtailment Service Provider’s market operations center or its agent.

Guaranteed Load Drop (GLD) – Load management achieved by an end-use customer reducing its load by a pre-determined amount (the Guaranteed Load Drop), upon notification from the Curtailment Service Provider’s market operations center or its agent. Typically, the load reduction is achieved through running customer-owned backup generators, or by shutting down process equipment.

H. Each Curtailment Service Provider must satisfy (or contract with another LSE, Curtailment Service Provider, or electric distribution company to provide) the following requirements:

● A point of contact with appropriate backup to ensure single call notification from PJM and timely execution of the notification process;

● Supplemental status reports, detailing Demand Resources available, as requested by PJM;

● Entry of customer-specific Demand Resource Registration information, for planning and verification purposes, into the designated PJM electronic system.

● Customer-specific compliance and verification information for each PJM-initiated Demand Resource event or Provider initiated test event, as well as aggregated Provider load drop data for Provider-initiated events, in accordance with established reporting guidelines.

● Load drop estimates for all Load Management events and test events, prepared in accordance with the PJM Manuals.

I. The Nominated Values (summer, winter or annual) for each Demand Resource Registration shall be determined consistent with the process described below.

The summer Nominated Value for Firm Service Level customer(s) on a registration will be based on the peak load contribution for the customer(s), as typically determined by the 5CP methodology utilized by the electric distribution company to determine ICAP obligation values. The summer Nominated Value for a registration shall equal the total peak load contribution for the customers on the registration minus the summer Firm Service Level multiplied by the loss factor. The winter Nominated Value for Firm Service Level customer(s) on a registration shall equal the total Winter Peak Load for customers on the registration multiplied by Zonal Winter Weather Adjustment Factor minus winter Firm Service level and then the result is multiplied by the loss factor. The annual Nominated Value for or Firm Service Level customer(s) on a registration shall equal the lesser of i) summer Nominated Value or ii) winter Nominated Value. Effective with the 2019/2020 Delivery Year, an annual Nominated Value for a registration is no longer calculated.

The summer Nominated Value for a Guaranteed Load Drop customer on a registrationshall equal the summer guaranteed load drop amount, adjusted for system losses and shall not exceed the customer's Peak Load Contribution, as established by the customer's contract with the Curtailment Service Provider. The winter Nominated Value for a Guaranteed Load Drop customer on a registration shall be the winter guaranteed load drop amount, adjusted for system losses, and shall not exceed the customer's Winter Peak Load multiplied by Zonal Winter Weather Adjustment Factor multiplied by the loss factor, as established by the customer's contract with the Curtailment Service Provider. The annual Nominated Value for a Guaranteed Load Drop customer on a registration shall be the lesser of the i) summer Nominated Value or ii) winter Nominated Value. Effective with the 2019/2020 Delivery Year, an annual Nominated Value for a registration is no longer calculated.

Customer-specific Demand Resource Registration information (EDC account number, peak load contribution, Winter Peak Load, notification period, etc.) will be entered into the designated PJM electronic system to establish nominated values. Each Demand Resource Registration should be linked to a Demand Resource. Additional data may be required, as defined in sections J and K and the PJM Manuals.

J. Nominated Values shall be reviewed based on documentation of customer-specific data and Demand Resource Registration information, to verify the amount of load management available and to set a summer, winter, or annual Nominated Value. Data is provided by both the zone EDC and the Curtailment Service Provider in the designated PJM electronic system, and must include the EDC meter number or other unique customer identifier, Peak Load Contribution (5CP), Winter Peak Load, contract firm service level or guaranteed load drop values, applicable loss factor, zone/area location of the load drop, number of active participants, etc. Such data must be uploaded and approved prior to the first day of the Delivery Year for which such Demand Resource Registration is effective. Curtailment Service Providers must provide this information concurrently to host EDCs.

For Firm Service Level and Guaranteed Load Drop customers, the 5CP values, for the zone and affected customers, will be adjusted to reflect an “unrestricted” peak for a zone, based on information provided by the Curtailment Service Provider. Load drop levels shall be estimated in accordance with guidelines in the PJM Manuals.

The daily Nominated Value for the Delivery Year for a Limited Demand Resource, Extended Summer Demand Resource, Base Capacity Demand Resource, and Annual Demand Resource without a Capacity Performance commitment shall equal the sum of the summer Nominated Values of the registrations linked to such Demand Resource. For the 2017/2018 and 2018/2019 Delivery Years, the daily Nominated Value for the Delivery Year for an Annual Demand Resource with a Capacity Performance commitment shall equal the sum of the annual Nominated Values of the registrations linked to such Demand Resource. For the 2019/2020 Delivery Year, the daily Nominated Value for the Delivery Year for an Annual Demand Resource with a Capacity Performance commitment shall equal the lesser of (i) the sum of the summer Nominated Values of the registrations linked to such Demand Resource or (ii) the sum of the winter Nominated Values of the registrations linked to such Demand Resource. Effective with the 2020/2021 Delivery Year, the daily Nominated Value of a Demand Resource with a Capacity Performance commitment (which may consist of an Annual Demand Resource with a Capacity Performance commitment and/or Summer Period Demand Resource with a Capacity Performance commitment) shall equal the sum of the summer Nominated Values of the registrations linked to such Demand Resource for the summer period of June through October and May of the Delivery Year, and shall equal the lesser of (i) the sum of the summer Nominated Values of the registrations linked to such Demand Resource or (ii) the sum of the winter Nominated Values of the registrations linked to such Demand Resource for the non-summer period of November through April of the Delivery Year.

K. Compliance is the process utilized to review Provider performance during PJM-initiated Load Management events and Curtailment Service Provider initiated tests. Compliance will be established for each Provider on an event specific basis for the Curtailment Service Provider’s Demand Resource Registrations dispatched by the Office of the Interconnection during such event. PJM will establish and communicate reasonable deadlines for the timely submittal of event data to expedite compliance reviews. Compliance reviews will be completed as soon after the event as possible, with the expectation that reviews of a single event will be completed within two months of the end of the month in which the event took place. Curtailment Service Providers are responsible for the submittal of compliance information to PJM for each PJM-initiated event and Curtailment Service Provider initiated test during the compliance period.

Compliance is measured for Market Participant Bonus Performance, as applicable, and Non-Performance Charges. Non-Performance Charges are assessed for the defined obligation period of each Demand Resource as defined in RAA, Article 1, subject to the following requirements:

Compliance is checked on an individual customer basis for Firm Service Level, by comparing actual load during the event to the firm service level. Current load for a statistical sample of end-use customers may be used for compliance for residential non-interval metered registrations in accordance with the PJM Manuals and subject to PJM approval. Curtailment Service Providers must submit actual customer load levels (for the event period) for the compliance report. Compliance for FSL will be based on:

> Summer (June through October and the following May of a Delivery Year)- End use customer's current Delivery Year peak load contribution ("PLC") minus the metered load ("Load") multiplied by the loss factor ("LF"). The calculation is represented by:
>
> (PLC) - (Load *LF)
>
> Winter (November through April of a Delivery Year)– End use customer's Winter Peak Load ("WPL") multiplied by Zonal Winter Weather Adjustment Factor ("ZWWAF") multiplied by LF, minus the metered load ("Load") multiplied by the LF. The calculation is represented by:
>
> (WPL * ZWWAF * LF) – (Load * LF)

Compliance is checked on an individual customer basis for Guaranteed Load Drop. Current load for a statistical sample of end-use customers may be used for compliance for residential non-interval metered registrations in accordance with the PJM Manuals and subject to PJM approval. Guaranteed Load Drop compliance will be based on:

(i) the lesser of (a) comparison load used to best represent what the load would have been if PJM did not declare a Load Management Event or the CSP did not initiate a test as outlined in the PJM Manuals, minus the Load and then multiplied by the LF, or (b) For a summer event, the PLC minus the Load multiplied by the LF. A summer load reduction will only be recognized for capacity compliance if the Load multiplied by the LF is less than the PLC. For a non-summer event, the WPL multiplied the ZWWAF multiplied by LF, minus the Load multiplied by the LF. A non-summer load reduction will only be recognized for capacity compliance if the Load multiplied by the LF is less than the WPL multiplied by the ZWWAF multiplied by LF.

(ii) Curtailment Service Providers must submit actual loads and comparison loads for all hours during the day of the Load Management Event or the Load Management performance test, and for all hours during any other days as required by the Office of the Interconnection to calculate the load reduction. Comparison loads must be developed from the guidelines in the PJM Manuals, and note which method was employed.

(iii) Methodologies for establishing comparison load for Guaranteed Load Drop end-use customers are described in greater detail in Manual M-19, PJM Manual for Load Forecasting and Analysis, at Attachment A: Load Drop Estimate Guidelines.

Load reduction compliance is averaged over the Load Management Event for a Demand Resource Registration linked to a Limited Demand Resource, Extended Summer Demand Resource, or Annual Demand Resource without a Capacity Performance commitment or determined on an hourly basis for a Demand Resource Registration linked to a Base Capacity Demand Resource or Annual Demand Resource with a Capacity Performance commitment, for each FSL and GLD customer dispatched by the Office of the Interconnection for at least 30 minutes of the clock hour (i.e., "partial dispatch compliance hour"). The registered capacity commitment for a Demand Resource Registration without a Base or Capacity Performance commitment for the partial dispatch compliance hour will be prorated based on the number of minutes dispatched during the clock hour and as defined in the Manuals. Curtailment Service Provider may submit 1 minute load data for use in capacity compliance calculations for partial dispatch compliance hours subject to PJM approval and in accordance with the PJM Manuals where: (a) metering meets all Tariff and Manual requirements, (b) 1 minute load data shall be submitted to PJM for all locations on the registration, and (c) 1 minute load data measures energy consumption over the minute. The registered capacity commitment for a Demand Resource Registration with a Base or Capacity Performance commitment is not prorated based on the number of minutes dispatched during the clock hours. The actual hourly load reduction for the hour ending that includes a Performance Assessment Interval(s) is flat-profiled over the set of dispatch intervals in the hour in accordance with the PJM Manuals.

A Demand Resource Registration may not reduce their load below zero (i.e., export energy into the system). No compliance credit will be given for an incremental load drop below zero.

Compliance will be totaled over all dispatched registrations for FSL and GLD customers linked to a committed Limited Demand Resource, Extended Summer Demand Resource, and Annual Demand Resource without a Capacity Performance commitment to determine a net compliance position for the event for each Provider by Compliance Aggregation Area and such net compliance position shall be allocated to the underlying registrations, in accordance with PJM Manuals. Load Management Event deficiencies shall be as further determined in accordance with Tariff, Attachment DD, section 11 and PJM Manuals.

For a Performance Assessment Interval, compliance will be totaled over all dispatched registrations for FSL and GLD customers linked to a Provider's Base Capacity Demand Resource or to an Annual Demand Resource with a Capacity Performance commitment to determine the Actual Performance for such Demand Resource in accordance with Tariff, Attachment DD, section 10A, and PJM Manuals. The Expected Performance for such Demand Resource shall be equal to the Provider's committed capacity on the Demand Resource, adjusted to account for any linked registrations that were not dispatched by PJM. A Provider's Demand Resources' initial Performance Shortfalls shall be netted for all the seller's Demand Resources in the Emergency Action Area to determine a net Emergency Action Area Performance Shortfall which is then allocated to the Capacity Market Seller's Demand Resources in accordance with Tariff, Attachment DD, section 10A, and PJM Manuals.

L. Energy Efficiency Resources

1. An Energy Efficiency Resource is a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during peak summer and winter periods as described herein) reduction in electric energy consumption at the End-Use Customer's retail site that is not reflected in the peak load forecast prepared for the Delivery Year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.

2. An Energy Efficiency Resource may be offered as a Capacity Resource in the Base Residual or Incremental Auctions for any Delivery Year beginning on or after June 1, 2011. No later than 30 days prior to the auction in which the resource is to be offered, the Capacity Market Seller shall submit to the Office of the Interconnection a notice of intent to offer the resource into such auction and a measurement and verification plan. The notice of intent shall include all pertinent project design data, including but not limited to the peak-load contribution of affected customers, a full description of the equipment, device, system or process intended to achieve the load reduction, the load reduction pattern, the project location, the project development timeline, and any other relevant data. Such notice also shall state the seller's proposed Nominated Energy Efficiency Value.

   - For Delivery Years through May 31, 2018 for all Energy Efficiency Resources not committed as a Capacity Performance Resource, the seller's proposed Nominated Energy Efficiency Value shall be the expected average load reduction between the hour ending 15:00 EPT and the hour ending 18:00 EPT during all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday;

   - For the 2018/2019 and 2019/2020 Delivery Years, the seller's proposed Nominated Energy Efficiency Value for any Base Capacity Energy Efficiency Resource shall be the expected average load reduction between the hour ending 15:00 EPT and the hour ending 18:00 EPT during all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday; and

- For the 2018/2019 Delivery Year and subsequent Delivery Years and for any Annual Energy Efficiency Resource committed as a Capacity Performance Resource for the 2016/2017 and 2017/2018 Delivery Years, the seller's proposed Nominated Energy Efficiency Value for any Annual Energy Efficiency Resources, shall be the expected average load reduction, for all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday, between the hour ending 15:00 EPT and the hour ending 18:00 EPT. In addition, the expected average load reduction for all days from January 1 through February 28, inclusive, of such Delivery Year that is not a weekend or federal holiday, between the hour ending 8:00 EPT and the hour ending 9:00 EPT and between the hour ending 19:00 EPT and the hour ending 20:00 EPT shall not be less than the Nominated Energy Efficiency Value; and

- For the 2020/2021 Delivery Year and subsequent Delivery Years, the seller's proposed Nominated Energy Efficiency Value for any Summer-Period Energy Efficiency Resource shall be the expected average load reduction between the hour ending 15:00 EPT and the hour ending 18:00 EPT during all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday.

  The measurement and verification plan shall describe the methods and procedures, consistent with the PJM Manuals, for determining the amount of the load reduction and confirming that such reduction is achieved. The Office of the Interconnection shall determine, upon review of such notice, the Nominated Energy Efficiency Value that may be offered in the Reliability Pricing Model Auction.

3. An Energy Efficiency Resource may be offered with a price offer or as Self-Supply. If an Energy Efficiency Resource clears the auction, it shall receive the applicable Capacity Resource Clearing Price, subject to section 5 below. A Capacity Market Seller offering an Energy Efficiency Resource must comply with all applicable credit requirements as set forth in Tariff, Attachment Q. For Delivery Years through May 31, 2018, or for FRR Capacity Plans for Delivery Years through May 31, 2019, the Unforced Capacity value of an Energy Efficiency Resource offered into an RPM Auction shall be the Nominated Energy Efficiency value times the DR Factor and the Forecast Pool Requirement. For the 2018/2019 Delivery Year and subsequent Delivery Years, or for FRR Capacity Plans for the 2019/2020 Delivery Year and subsequent Delivery Years, the Unforced Capacity value of an Energy Efficiency Resource offered into an RPM Auction shall be the Nominated Energy Efficiency Value times the Forecast Pool Requirement.

4. An Energy Efficiency Resource that clears an auction for a Delivery Year may be offered in auctions for up to three additional consecutive Delivery Years, but shall

not be assured of clearing in any such auction; provided, however, an Energy Efficiency Resource may not be offered for any Delivery Year in which any part of the peak season is beyond the expected life of the equipment, device, system, or process providing the expected load reduction; and provided further that a Capacity Market Seller that offers and clears an Energy Efficiency Resource in a BRA may elect a New Entry Price Adjustment on the same terms as set forth in Tariff, Attachment DD, section 5.14(c).

5. For every Energy Efficiency Resource clearing an RPM Auction for a Delivery Year, the Capacity Market Seller shall submit to the Office of the Interconnection, by no later than 30 days prior to each Auction an updated project status and measurement and verification plan subject to the criteria set forth in the PJM Manuals.

6. For every Energy Efficiency Resource clearing an RPM Auction for a Delivery Year, the Capacity Market Seller shall submit to the Office of the Interconnection, by no later than the start of such Delivery Year, an updated project status and detailed measurement and verification data meeting the standards for precision and accuracy set forth in the PJM Manuals. The final value of the Energy Efficiency Resource during such Delivery Year shall be as determined by the Office of the Interconnection based on the submitted data.

7. The Office of the Interconnection may audit, at the Capacity Market Seller's expense, any Energy Efficiency Resource committed to the PJM Region. The audit may be conducted any time including the Performance Hours of the Delivery Year.

8. For Incremental Auctions conducted for the 2019/2020 and 2020/2021 Delivery Years, and for RPM Auctions for the 2021/2022 Delivery Year and subsequent Delivery Years, if a Relevant Electric Retail Regulatory Authority receives FERC authorization to qualify or prohibit Energy Efficiency Resource participation in a specific area(s) of the PJM Region, the following process applies:

(a) The Office of the Interconnection will publicly post a reference to the FERC authorization of a Relevant Electric Retail Regulatory Authority order, ordinance or resolution that qualifies or prohibits Energy Efficiency Resource participation, the applicable electric distribution company(ies), and the applicable auction(s) and/or Delivery Year(s).

(b) A Capacity Market Seller that intends to offer or certify Energy Efficiency Resources must identify and itemize all resources that are located in the jurisdiction of a Relevant Electric Retail Regulatory Authority authorized by FERC to qualify or prohibit Energy Efficiency Resource participation within the

Zone or LDA, as required, and those outside of the area but within the Zone or LDA, as required.

(c) A Capacity Market Seller that intends to offer or certify Energy Efficiency Resources must identify and itemize all Energy Efficiency Resources to be offered as part of its Energy Efficiency measurement and verification plan and certified post-installation measurement and verification report. The Office of Interconnection will provide a list to the relevant electric distribution company for the specific area(s) to review for compliance with the Relevant Electric Retail Regulatory Authority of Capacity Market Sellers that are:

(i) offering Energy Efficiency Resources in an RPM Auction within two (2) Business Days after the deadline for submitting an energy efficiency measurement and verification plan for such RPM Auction; and

(ii) certifying Energy Efficiency Resources with a Delivery Year post-installation measurement and verification report, within two (2) Business Days of receipt of such Delivery Year post-installation measurement and verification report.The relevant electric distribution company for the specific area(s) shall review for compliance with rules from a Relevant Electric Retail Regulatory Authority authorized by FERC to qualify or prohibit Energy Efficiency Resource.

(d) The relevant electric distribution company for the specific area(s) shall review for compliance with rules from a Relevant Electric Retail Regulatory Authority authorized by FERC to qualify or prohibit Energy Efficiency Resource participation and provide a response to the Office of the Interconnection within five (5) Business Days after receiving the list of Capacity Market Sellers offering Energy Efficiency Resources. The Office of the Interconnection will not allow a Capacity Market Seller to offer or certify Energy Efficiency Resources if an electric distribution company denies such Capacity Market Seller to deliver Energy Efficiency Resources in compliance with rules of a Relevant Electric Retail Regulatory Authority authorized by FERC to qualify or prohibit Energy Efficiency Resource participation.

(9) For Incremental Auctions that will be conducted for the 2019/2020 and 2020/2021 Delivery Years, and for RPM Auctions for the 2021/2022 Delivery Year and subsequent Delivery Years, a Capacity Market Seller of Energy Efficiency Resources that cannot satisfy its RPM obligations in any Delivery Year due to the prohibition of participation by a Relevant Electric Retail Regulatory Authority authorized by FERC to prohibit participation of such resources may be

relieved of its Capacity Resource Deficiency Charge by notifying the Office of the Interconnection by no later than seven (7) calendar days prior to the posting of the planning parameters for the Third Incremental Auction of that Delivery Year. After providing such notice, the affected Capacity Market Seller may elect to be relieved of its RPM commitment, and shall not be required to obtain replacement capacity for the resource, and no charges shall be assessed by the Office of the Interconnection for the Capacity Market Seller's deficiency in satisfying its RPM obligation for the resource for such Delivery Year. In such case, however, the Capacity Market Seller shall not be entitled to, nor be paid, any RPM revenues for such resource for that Delivery Year. The Office of the Interconnection will apply corresponding adjustments to the quantity of Buy Bids or Sell Offers in the Incremental Auctions for such Delivery Years in accordance with Tariff, Attachment DD, sections 5.12(b)(ii) and 5.12(b)(iii).

Attachment D

Brattle 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 No. ER18-1314**
PJM Interconnection, L.L.C.	**)**	**Docket No. EL18-178 (Consolidated)**

AFFIDAVIT OF SAMUEL A. NEWELL, JOHN M. HAGERTY AND SANG H. GANG ON BEHALF OF PJM INTERCONNECTION, L.L.C.

1. Our names are Dr. Samuel A. Newell, John M. Hagerty and Sang H. Gang. Dr. Newell is employed by The Brattle Group ("Brattle") as a Principal and Mr. Hagerty, as a Senior Associate. Mr. Gang is employed by Sargent & Lundy ("S&L") as a Principal Consultant. We are submitting this affidavit in support of PJM Interconnection, L.L.C.'s ("PJM") filing in compliance with the December 2019 order by the Federal Energy Regulatory Commission ("FERC") related to the expansion of the Minimum Offer Price Rule ("MOPR") in its forward capacity market.

2. Dr. Newell is an economist and engineer with more than 20 years of experience consulting in electricity wholesale design, market analysis, generation asset valuation, integrated resource planning, and transmission planning. He has led studies on the cost of generation for past PJM Quadrennial/Triennial reviews of the Net Cost of New Entry and for ISO-NE on the same and for Offer Review Trigger Prices. Prior to joining The Brattle Group in 2004, he was the Director of the

Transmission Service at Cambridge Energy Research Associates and previously a Manager in the Utilities Practice at A.T.Kearney. He earned a Ph.D. in Technology Management and Policy from the Massachusetts Institute of Technology, an M.S. in Materials Science and Engineering from Stanford University, and a B.A. in Chemistry and Physics from Harvard College.

3. Mr. Hagerty is an electricity market analyst and engineer with more than 5 years of experience analyzing and modeling electricity wholesale markets, the transmission system, and RTO market rules. He earned a M.S. in Technology and Policy from the Massachusetts Institute of Technology and a B.Sc. in Chemical Engineering from the University of Notre Dame.

4. Mr. Gang is an engineer with 10 years of experience in engineering design and consulting on a wide range of electric power projects including nuclear, gas, coal, biomass, wind, solar PV, and battery energy storage technologies. He has extensive experience assessing power plant technologies and estimating plant capital costs, operation and maintenance ("O&M") costs, and performance characteristics. Within the last two years, Mr. Gang has been leading Sargent & Lundy's electric power resource planning projects including evaluation of various generation and interconnection options. Mr. Gang also led the Sargent & Lundy team in working with Brattle to estimate the CONE for new merchant generation resources for PJM in its past Quadrennial Review and for the Alberta Electric System Operator in its development of a centralized capacity market in Alberta, Canada. Mr. Gang is a licensed Professional Engineer in the State of Illinois and earned a B.S. in Electrical Engineering from the University of Illinois at Urbana-Champaign.

5. Complete details of our qualifications, publications, reports, and prior experiences are set forth in our resumes included as Exhibit No. 1 to our affidavit.

6. In January, 2020, PJM retained Brattle and S&L to analyze the gross avoidable costs rates ("ACR") for several types of existing generation and the net cost of new entry ("Net CONE") for new energy efficiency ("EE") in the 2022/2023 Base Residual Auction. The results of the analysis completed by Brattle and S&L are set forth in a report entitled "Gross Avoidable Cost Rates for Existing Generation and Net Cost of New Entry for New Energy Efficiency" ("Gross ACR and EE Net CONE Study"). A copy of the Gross ACR and EE Net CONE Study, which was prepared under our direction and supervision, is included as Exhibit No. 2 to our affidavit.

7. This affidavit summarizes the methodology and results of our study.

8. Existing generation resources vary considerably in their characteristics and costs, even for a given type of resource. To inform PJM's determination of a single ACR for each resource type, we present a range of costs for the fleet of resources of each type operating in the PJM market. PJM can then determine the default offer floor price for each resource type at a value within the range that best fits its approach to

complying with the order, trading off the risks of under-mitigation against the risks of over-mitigation and/or a burdensome amount of unit-specific reviews.

9. To do so, we reviewed the range of characteristics of resources installed in the PJM market and identified the primary cost drivers among those characteristics for each resource type. We then identified for each resource type the characteristics of a "representative plant" that is widely representative of most of the fleet as well as characteristics for "representative low-cost" and "representative high-cost" plants to inform the range of costs for each type of existing generation resource.

10. Given the assumed characteristics, we then estimated the costs of the representative plants to inform the Gross ACRs and the variable O&M costs for use in PJM's net energy and ancillary services ("E&AS") revenues analysis. These cost estimates reflect PJM's market rules concerning the scope of costs that are includable in the Gross ACRs versus those that can be included in cost-based energy offers (and thus accounted for in the net E&AS revenue component of Net ACRs). Following guidance provided by PJM, the costs of major maintenance and overhauls on systems directly related to the production of electricity are included in variable costs as a "maintenance adder."

11. Table 1 below shows the resulting cost estimates for each existing generation resource type on a per-megawatt ("MW") of nameplate capacity basis for informing PJM's 2022/2023 Gross ACRs.

Table 1
Existing Generation Costs for 2022/2023 Gross Avoidable Cost Rates
(in nominal dollars per MW-day)

Resource Type	Representative Low-Cost Plant	Representative Plant	Representative High-Cost Plant
Single-Unit Nuclear	---	$697	---
Multi-Unit Nuclear	$405	$445	$457
Coal	$74	$80	$166
Gas CC	$55	$56	$79
Gas CT	$42	$50	$65
Onshore Wind	$76	$83	$128
Solar PV	$29	$40	$60
Diesel Generator	---	$3	---

12. Table 2 below shows our estimates of the variable costs for each resource type that are consistent with the Gross ACR estimates. The variable costs shown include non-fuel operating costs and maintenance adders for all resource types.

Table 2
Existing Generation Costs for 2022/2023 Variable Costs
(in nominal dollars per MWh)

Resource Type	Representative Low-Cost Plant	Representative Plant	Representative High-Cost Plant
Single-Unit Nuclear	---	$4.00	---
Multi-Unit Nuclear	$2.63	$2.67	$3.66
Coal	$9.17	$9.56	$9.20
Gas CC	$2.24	$2.57	$2.53
Gas CT	$7.54	$7.54	$4.98
Onshore Wind	$0.00	$0.00	$0.00
Solar PV	$0.00	$0.00	$0.00
Diesel Generator	---	$0.00	---

13. To calculate the Net CONE for new EE resources, we analyzed the total costs and benefits of EE programs. Net CONE represents the amount of capacity market revenues that a resource would need to justify the investment. It represents the gap between the total costs of the EE investments (including all utility program costs and participant's out-of-pocket costs) and other revenues or benefits of EE (reduced wholesale energy costs and transmission and distribution system costs) that would need to be filled by revenues from the capacity market.

14. We reviewed publicly-available reports on EE program cost effectiveness and identified sufficient costs and performance data to calculate Net CONE for EE programs of three representative PJM utilities with the largest EE portfolios in their respective states: Baltimore Gas and Electric, Pennsylvania Power and Light, and Commonwealth Edison. For those utilities, we identified 30 programs whose capacity could qualify for PJM's capacity market. We then calculated the Net CONE for each EE program by analyzing its costs, characteristics, and benefits per MW of qualified capacity. Finally, we calculated the capacity-weighted average across all qualified programs to produce a single Net CONE value for EE.

15. The estimated Net CONE for new EE resources in the 2022/2023 Base Residual Auction is $64/MW ICAP-day, or $58/MW UCAP-day (in nominal dollars).

16. This concludes our affidavit.

Exhibit No. 1

SAMUEL A. NEWELL

Principal

Boston, MA | +1.617.234.5725 | Sam.Newell@brattle.com

Dr. Samuel Newell co-leads The Brattle Group's Electricity Practice. He has more than 20 years of experience supporting clients in wholesale market design, generation asset valuation, resource planning, and transmission planning. Much of his work addresses the industry's transition to clean energy. He frequently provides testimony and expert reports to Independent System Operators (ISOs), the Federal Energy Regulatory Commission (FERC), state regulatory commissions, and the American Arbitration Association.

Dr. Newell earned a Ph.D. in Technology Management & Policy from the Massachusetts Institute of Technology, an M.S. in Materials Science & Engineering from Stanford University, and a B.A. in Chemistry & Physics from Harvard College.

Prior to joining The Brattle Group in 2004, Dr. Newell was the Director of the Transmission Service at Cambridge Energy Research Associates. Before that, he was a Manager at A.T. Kearney.

AREAS OF EXPERTISE

- Electricity Market Design and Analysis
- Generation and Storage Asset Valuation
- Transmission Planning and Modeling
- Integrated Resource Planning
- Demand Response (DR) Resource Potential and Market Impact
- Gas-Electric Coordination
- RTO Participation and Configuration
- Energy Litigation
- Tariff and Rate Design
- Business Strategy

EXPERIENCE

Electricity Market Design and Analysis

- **Singapore Capacity Market Development**. For the Energy Market Authority in Singapore, currently developing a complete forward capacity market design.
- **Electricity Market Transformation Study**. For NYISO, led a team to conduct simulation analyses of how prices for energy, ancillary services, capacity, and RECs may have to evolve to support adequate generation/storage investment to maintain reliability and meet the state's mandates for 70% renewable electricity by 2030 and 100% carbon-free electricity by 2040. Used a proprietary optimization model, GridSIM, to model investment and chronological operation with large amounts of intermittent and storage resources, subject to reliability and environmental

constraints, under a range of assumptions regarding market design and carbon pricing. Results and insights to inform NYISO's *Grid in Transition* whitepaper.

- **PJM's Capacity Market Reviews**. For PJM, conducted all four official reviews of its Reliability Pricing Model (2008, 2011, 2014, and 2018). Analyzed capacity auctions and interviewed stakeholders. Evaluated the demand curve shape, the Cost of New Entry (CONE) parameter, and the methodology for estimating net energy and ancillary services revenues. Recommended improvements to support participation and competition, to avoid excessive price volatility, and to safeguard future reliability performance. Submitted testimonies before FERC.
- **Seasonal Capacity in PJM.** On behalf of the Natural Resources Defense Council, analyzed the ability of PJM's capacity market to efficiently accommodate seasonal capacity resources and meet seasonal resource adequacy needs. Co-authored a whitepaper proposing a co-optimized two-season auction and estimating the efficiency benefits. Filed and presented report at FERC.
- **Energy Price Formation in PJM**. For NextEra Energy, analyzed PJM's integer relaxation proposal and evaluated implications for day-ahead and real-time market prices. Reviewed PJM's Fast-Start pricing proposal and authored report recommending improvements, which NextEra and other parties filed with FERC, and which FERC largely accepted and cited in its April 2019 Order.
- **Carbon Pricing to Harmonize NY's Wholesale Market and Environmental Goals**. Led a Brattle team to help NYISO: (1) develop and evaluate market design options, including mechanisms for charging emitters and allocating revenues to customers, border adjustments to prevent leakage, and interactions with other market design and policy elements; and (2) develop a model to evaluate how carbon pricing would affect market outcomes, emissions, system costs, and customer costs under a range of assumptions. Whitepaper initiated discussions with NY DPS and stakeholders. Supported NYISO in detailed market design and stakeholder engagement.
- **Market Design for Energy Security in ISO-NE**. For NextEra Energy, evaluated and developed proposals for meeting winter energy security needs in New England when pipeline gas becomes scarce. Evaluated ISO-NE's proposed multi-day energy market with new day-ahead operating reserves. Developed competing proposal for new operating reserves in both day-ahead and real-time to incent preparedness for fuel shortages; also developed criteria and high-level approach for potentially incorporating energy security into the forward capacity market. Presented evaluations and proposals to the NEPOOL Markets Committee.
- **ERCOT's Proposed Future Ancillary Services Design**. For the Electric Reliability Council of Texas (ERCOT), evaluated the benefits of its proposal to unbundle ancillary services, enable broader participation by load resources and new technologies, and tune its procurement amounts to system conditions. Worked with ERCOT staff to assess each ancillary service and how generation, load

resources, and new technologies could participate. Directed their simulation of the market using PLEXOS, and evaluated other benefits outside of the model.

- **Investment Incentives and Resource Adequacy in ERCOT**. For ERCOT, led a Brattle team to: (1) interview stakeholders and characterize the factors influencing generation investment decisions; (2) analyze the energy market's ability to support investment and resource adequacy at the target level; and (3) evaluate options to enhance long-term resource adequacy while maintaining market efficiency. Worked with ERCOT staff to understand the relevant aspects of their operations and market data. Performed probabilistic simulation analyses of prices, investment costs, and reliability. Conclusions informed a PUCT proceeding in which I filed comments and presented at several workshops.
- **Operating Reserve Demand Curve (ORDC) in ERCOT**. For ERCOT, evaluated several alternative ORDCs' effects on real-time price formation and investment incentives. Conducted backcast analyses using interval-level data provided by ERCOT and assuming generators rationally modify their commitment and dispatch in response to higher prices under the ORDC. Analysis was used by ERCOT and the PUCT to inform selection of final ORDC parameters.
- **Economically Optimal Reserve Margins in ERCOT**. For ERCOT, co-led studies (2014 and 2018) estimating the economically-optimal reserve margin, and the market equilibrium reserve margins in its energy-only market. Collaborated with ERCOT staff and Astrape Consulting to construct Monte Carlo economic and reliability simulations. Accounted for uncertainty and correlations in weather-driven load, renewable energy production, generator outages, and load forecasting errors. Incorporated intermittent wind and solar generation profiles, fossil generators' variable costs, operating reserve requirements, various types of demand response, emergency procedures, administrative shortage pricing under ERCOT's ORDC, and criteria for load-shedding. Reported economic and reliability metrics across a range of renewable penetration and other scenarios. Results informed the PUCT's adjustments to the ORDC to support desired reliability outcomes.
- **Australian Electricity Market Operator (AEMO) Redesign**. Advised AEMO on market design reforms for the National Electricity Market (NEM) to address concerns about operational reliability and resource adequacy as renewable generation displaces traditional resources. Also provided a report on potential auctions to ensure sufficient capabilities in the near-term.
- **Response to DOE's "Grid Reliability and Resiliency Pricing" Proposal**. For a broad group of stakeholders opposing the rule in a filing before FERC, evaluated DOE's proposed rule: the need (or lack thereof) for bolstering reliability and resilience by supporting resources with a 90-day fuel supply; the likely cost of the rule; and the incompatibility of DOE's proposed solution with the principles and function of competitive wholesale electricity markets.

- **Energy Market Power Mitigation in Western Australia**. Led a Brattle team to help Western Australia's Public Utilities Office design market power mitigation measures for its newly reformed energy market. Established objectives; interviewed stakeholders; assessed local market characteristics affecting the design; synthesized lessons learned from the existing energy market and from several international markets. Recommended criteria, screens, and mitigation measures for day-ahead and real-time energy and ancillary services markets. The Public Utilities Office posted our whitepaper in support of its conclusions.
- **MISO Competitive Retail Choice Solution.** For MISO, evaluated design alternatives for accommodating the differing needs of states relying on competitive retail choice and integrated resource planning. Conducted probabilistic simulations of likely market results under alternative market designs and demand curves. Provided expert support in stakeholder forums and submitted expert testimony before FERC.
- **Buyer Market Power Mitigation**. On Behalf of the "Competitive Markets Coalition" group of generating companies, helped develop and evaluate proposals for improving PJM's Minimum Offer Price Rule so that it more effectively protects the capacity market from manipulation by buyers while reducing interference with non-manipulative activity. Participated in discussions with other stakeholders. Submitted testimony to FERC supporting tariff revisions that PJM filed.
- **Market Development Vision for MISO**. For the Midcontinent Independent System Operator (MISO), worked with MISO staff and stakeholders to codify a Market Vision as the basis for motivating and prioritizing market development initiatives over the next 2–5 years. Authored a foundational report for that Vision, including: describing the core services MISO must continue to provide to support a well-functioning market; establishing a set of principles for enhancing those services; identifying seven Focus Areas offering the greatest opportunities; and proposing criteria for prioritizing initiatives within and across Focus Areas.
- **ISO-NE Capacity Demand Curve Design.** For ISO New England (ISO-NE), developed a demand curve for its Forward Capacity Market. Solicited staff and stakeholder input, then established market design objectives. Provided a range of candidate curves and evaluated them against objectives, showing tradeoffs between reliability uncertainty and price volatility (using a probabilistic locational capacity market simulation model we developed). Worked with Sargent & Lundy to estimate the Net Cost of New Entry to which the demand curve prices are indexed. Submitted testimonies before FERC, which accepted the proposed curve.
- **Offer Review Trigger Prices in ISO-NE**. For the Internal Market Monitor in ISO-NE, developed benchmark prices for screening for uncompetitively low offers in the Forward Capacity Market. Worked with Sargent & Lundy to conduct bottom-up analyses of the costs of constructing and operating gas-fired generation technologies and onshore wind; also estimated the costs of energy efficiency and

demand response. For each technology, estimated capacity payments needed to make the resource economically viable, given their costs and expected non-capacity revenues. Recommendations were filed with and accepted by the FERC.

- **Western Australia Capacity Market Design**. For the Public Utilities Office (PUO) of Western Australia, led a Brattle team to advise on the design and implementation of a new forward capacity market. Reviewed the high-level forward capacity market design proposed by the PUO; evaluated options for auction parameters such as the demand curve; recommended supplier-side and buyer-side market power mitigation measures; helped define administrative processes needed to conduct the auction and the governance of such processes.
- **Western Australia Reserve Capacity Mechanism**. For EnerNOC, evaluated Western Australia's administrative Reserve Capacity Mechanism in comparison with international capacity markets, and made recommendations for improvements to meet reliability objectives more cost effectively. Evaluated whether to develop an auction-based capacity market compared or an energy-only market design. Submitted report and presented recommendations to the Electricity Market Review Steering Committee and other senior government officials.
- **Evaluation of Moving to a Forward Capacity Market in NYISO.** For NYISO, conducted a benefit-cost analysis of replacing its prompt capacity market with a 4-year forward capacity market. Evaluated options based on stakeholder interviews and the experience of PJM and ISO-NE. Addressed risks to buyers and suppliers, market power mitigation, implementation costs, and long-run costs. Recommendations were used by NYISO and stakeholders to help decide whether to pursue a forward capacity market.
- **MISO's Resource Adequacy Construct and Market Design Elements.** For MISO, conducted the first major assessment of its resource adequacy construct. Identified several successes and recommended improvements in load forecasting, locational resource adequacy, and the determination of reliability targets. Incorporated extensive stakeholder input and review. Continued to consult with MISO in its work with the Supply Adequacy Working Group on design improvements, including market design elements for its annual locational capacity auctions.
- **Demand Response (DR) Integration in MISO**. Through a series of assignments, helped MISO incorporate DR into its energy market and resource adequacy construct, including: (1) conducted an independent assessment of MISO's progress in integrating DR into its resource adequacy, energy, and ancillary services markets. Analyzed market participation barriers; (2) wrote a whitepaper evaluating various approaches to incorporating economic DR in energy markets. Identified implementation barriers and recommended improvements to efficiently accommodate curtailment service providers; (3) helped modify MISO's tariff and business practices to accommodate DR in its resource adequacy construct by

defining appropriate participation rules. Informed design by surveying the practices of other RTOs and by characterizing the DR resources within the MISO footprint.

- **Survey of Demand Response Provision of Energy, Ancillary Services, and Capacity.** For the Australian Energy Market Commission (AEMC), co-authored a report on market designs and participation patterns in several international markets. AEMC used the findings to inform its integration of DR into its National Energy Market.
- **Integration of DR into ISO-NE's Energy Markets.** For ISO-NE, provided analysis and assisted with a stakeholder process to develop economic DR programs to replace the ISO's initial economic DR programs when they expired.
- **Compensation Options for DR in ISO-NE's Energy Market**. For ISO-NE, analyzed the implications of various DR compensation options on consumption patterns, LMPs, capacity prices, consumer surplus, producer surplus, and economic efficiency. Presented findings in a whitepaper that ISO-NE submitted to FERC.
- **ISO-NE Forward Capacity Market (FCM) Performance.** With ISO-NE's internal market monitor, reviewed the performance of the first two forward auctions. Evaluated key design elements regarding demand response participation, capacity zone definition and price formation, an alternative pricing rule for mitigating the effects of buyer market power, the use of the Cost of New Entry in auction parameters, and whether to have an auction price ceiling and floor.
- **Evaluation of Tie-Benefits**. For ISO-NE, analyzed the implications of different levels of tie-benefits (i.e., assistance from neighbors, reducing installed capacity requirements) for capacity costs and prices, emergency procurement costs, and energy prices. Whitepaper submitted by ISO-NE to the FERC.
- **Evaluation of Major Initiatives**. With ISO-NE and its stakeholders, developed criteria for identifying "major" market and planning initiatives that trigger the need for the ISO to provide qualitative and quantitative information to help stakeholders evaluate the initiative, as required in ISO-NE's tariff. Developed guidelines on the kinds of information ISO-NE should provide for major initiatives.
- **Energy Market Monitoring & Market Power Mitigation**. For PJM, co-authored a whitepaper, "Review of PJM's Market Power Mitigation Practices in Comparison to Other Organized Electricity Markets."
- **Vertical Market Power**. Before the NYPSC, examined whether the merger between National Grid and KeySpan could create incentives to exercise vertical market power. Employed a simulation-based approach using the DAYZER model of the NYISO wholesale power market and examined whether outages of National Grid's transmission assets significantly affected KeySpan's generation profits.
- **LMP Impacts on Contracts**. For a West Coast client, reviewed the California ISO's proposed implementation of locational marginal pricing (LMP) in 2007 and analyzed implications for "seller's choice" supply contracts. Estimated congestion

costs ratepayers would face if suppliers financially delivered power to the lowest priced nodes; estimated incremental contract costs using a third party's GE-MAPS market simulations (and helped to improve their model inputs to more accurately reflect the transmission system in California). Applied findings to support the ISO in design modifications of the California market under LMP.

- **RTO Accommodation of Retail Access**. For MISO, identified business practice improvements to facilitate retail access. Analyzed retail access programs in IL, MI, and OH. Studied retail accommodation practices in other RTOs, focusing on how they modified their procedures surrounding transmission access, qualification of capacity resources, capacity markets, FTR allocations, and settlement.

Generation and Storage Asset Valuation

- **Valuation of a Gas-Fired Combined-Cycle Plant in New England**. For a party to litigation, submitted testimony on the fair market value of the plant. Simulated energy and capacity markets to forecast net revenues, and estimated exposure to capacity performance penalties. Compared the valuation to the transaction prices of similar plants and analyzed the differences. Collaborated with a co-testifying export on project finance to assess whether the estimated value would suffice to cover the plant's debt and certain other obligations.
- **Valuation of a Portfolio of Combined-Cycle Plants across the U.S.** For a debt holder in a portfolio of plants, estimated the fair market value of each plant in 2018 and the plausible range of values five years hence. Reviewed comparables. Analyzed electricity markets in New England, New York, Texas, Arizona, and California using our own models and reference points from futures markets and publicly available studies. Performed probability-weighted discounted cash flow valuation analyses across a range of scenarios. Provided insights into market and regulatory drivers and how they may evolve.
- **Wholesale Market Value of Storage in PJM**. For a potential investor in battery storage, estimated the energy, ancillary services, and capacity market revenues their technology could earn in PJM. Reviewed PJM's market participation rules for storage. Forecast capacity market revenues and the risk of performance penalties. Developed a real-time energy and ancillary service bidding algorithm that the asset owner could employ to nearly optimize its operations, given expected prices and operating constraints. Identified changes in real-time bid/offer rules that PJM could implement to improve the efficiency of market participation by storage resources.
- **Valuation of a Generation Portfolio in ERCOT**. For the owners of a portfolios of gas-fired assets (including a cogen plant), estimated the market value of their assets by modeling future cash flows from energy and ancillary services markets over a range of plausible scenarios. Analyzed the effects load growth, entry, retirements, environmental regulations, and gas prices could have on energy prices, including

scarcity prices under ERCOT's Operating Reserve Demand Curve. Evaluated how future changes in these drivers could cause the value to shift over time.

- **Valuation Methodology for a Coal Plant Transaction in PJM**. For a part owner of a very large coal plant being transferred at an assessed value that was yet to be determined by a third party, wrote a manual describing how to conduct a market valuation of the plant. Addressed drivers of energy and capacity value; worked with an engineering subcontractor to describe how to determine the remaining life of the plant and CapEx needs going forward. Our manual was used to inform their pre-assessment negotiation strategy.
- **Valuation of a Coal Plant in PJM**. For the lender to a bidder on a coal plant being auctioned, estimated the market value of the plant. Valuation analysis focused especially on the effects of coal and gas prices on cash flows, and the ongoing fixed O&M costs and CapEx needs of the plant.
- **Valuation of a Coal Plant in New England**. For a utility, evaluated a coal plant's economic viability and market value. Projected market revenues, operating costs, and capital investments needed to comply with future environmental mandates.
- **Valuation of Generation Assets in New England**. To inform several potential buyers' valuations of various assets being sold in ISO-NE, provided energy and capacity price forecasts and cash flows under multiple scenarios. Explained the market rules and fundamentals to assess key risks to cash flows.
- **Valuation of Generation Asset Bundle in New England**. For the lender to the potential buyer of generation assets, provided long-term energy and capacity price forecasts, with multiple scenarios to test whether the plant could be worth less than the debt. Reviewed a broad scope of documents available in the "data room" to identify market, operational, and fuel supply risks.
- **Valuation of Generation Asset Bundle in PJM**. For a potential buyer, provided energy and capacity price forecasts and reviewed their valuation analysis. Analyzed supply and demand fundamentals of the PJM capacity market. Performed locational market simulations using the DAYZER model to project nodal prices as market fundamentals evolve. Reviewed the client's spark spread options model.
- **Wind Power Development**. For a developer proposing to build a several hundred megawatt wind farm in Michigan, provided a revenue forecast for energy and capacity. Evaluated the implications of several scenarios around key uncertainties.
- **Wind Power Financial Modeling**. For an offshore wind developer proposing to build a 350 MW project in PJM off the coast of New Jersey, analyzed market prices for energy, renewable energy certificates, and capacity. Provided a detailed financial model of project funding and cash distributions to various types of investors (including production tax credit). Resulting financial statements were used in an application to the state of New Jersey for project grants.

- **Contract Review for Cogeneration Plant**. For the owner of a large cogen plant in PJM, analyzed revenues under the terms of a long-term PPA (in renegotiation) vs. potential merchant revenues. Accounted for multiple operating modes of the plant and its sales of energy, capacity, ancillary services, and steam over time.
- **Generation Strategy/Valuation**. For an independent power producer, acted for over two years as a key advisor on the implementation of the client's growth strategy. Led a large analytical team to assess the profitability of proposed new power plants and acquisitions of portfolios of plants throughout the U.S. Used the GE-MAPS market simulation model to forecast power prices, transmission congestion, generator dispatch, emissions costs, energy margins for candidate plants; used an ancillary model to forecast capacity value.
- **Generation Asset Valuation**. For multiple banks and energy companies, provided valuations of financially distressed generating assets. Used GE-MAPS to simulate net energy revenues; a capacity model to estimate capacity revenues; and a financial valuation model to value several natural gas, coal, and nuclear power plants across a range of scenarios. Identified key uncertainties and risks.

Transmission Planning and Modeling

- **Economic and Environmental Evaluation of New Transmission to Quebec**. For the New Hampshire Attorney General's Office in a proceeding before the state Site Evaluation Committee, co-sponsored testimony on the benefits of the proposed Northern Pass Transmission line. Responded to the applicant's analysis and developed our own, focusing on wholesale market participation, price impacts, and net emissions savings.
- **Benefit-Cost Analysis of New York AC Transmission Upgrades**. For the New York Department of Public Service (DPS) and NYISO, led a team to evaluate 21 alternative projects to increase transfer capability between Upstate and Southeast NY. Quantified a broad scope of benefits: traditional production cost savings from reduced congestion, using GE-MAPS; additional production cost savings considering non-normal conditions; resource cost savings from being able to retire Downstate capacity, delay new entry, and shift the location of future entry Upstate; avoided costs from replacing aging transmission that would have to be refurbished soon; reduced costs of integrating renewable resources Upstate; and tax receipts. Identified projects with greatest and most robust net value. DPS used our analysis to inform its recommendation to the NY Public Service Commission to declare a "Public Policy Need" to build a project such as the best ones identified.
- **Evaluation of New York Transmission Projects**. For the New York Department of Public Service (DPS), provided a cost-benefit analysis for the "TOTS" transmission projects. Showed net production cost and capacity resource cost savings exceeding

the project costs, and the lines were approved. The work involved running GE-MAPS and a capacity market model, and providing insights to DPS staff.

- **Benefits of New 765kV Transmission Line**. For a utility joint venture between AEP and ComEd, analyzed renewable integration and congestion relief benefits of their proposed $1.2 billion RITELine project in western PJM. Guided client staff to conduct simulations using PROMOD. Submitted testimony to FERC.

- **Benefit-Cost Analysis of a Transmission Project for Offshore Wind**. Submitted testimony on the economic benefits of the Atlantic Wind Connection Project, a proposed 2,000 MW DC offshore backbone from New Jersey to Virginia with 7 onshore landing points. Described and quantified the effects on congestion, capacity markets, CO_2 emissions, system reliability and operations, jobs and economic stimulus, and the installed cost of offshore wind generation. Directed Ventyx staff to simulate the energy market impacts using the PROMOD model.

- **Analysis of Transmission Congestion and Benefits**. Analyzed the impacts on transmission congestion, and customer benefits in California and Arizona of a proposed inter-state transmission line. Used the DAYZER model to simulate congestion and power market conditions in the Western Electricity Coordination Council region in 2013 and 2020 considering increased renewable generation requirements and likely changes to market fundamentals.

- **Benefit-Cost Analysis of New Transmission**. For a transmission developer's application before the California Public Utility Commission (CPUC) to build a new 500 kV line, analyzed the benefits to ratepayers. Analysis included benefits beyond those captured in a production cost model, including the benefits of integrating a pumped storage facility that would allow the system to accommodate a larger amount of intermittent renewable resources at a reduced cost.

- **Benefit-Cost Analysis of New Transmission in the Midwest**. For the American Transmission Company (ATC), supported Brattle witness evaluating the benefits of a proposed new 345 kV line (Paddock-Rockdale). Advised client on its use of PROMOD IV simulations to quantify energy benefits, and developed metrics to properly account for the effects of changes in congestion, losses, FTR revenues, and LMPs on customer costs. Developed and applied new methodologies for analyzing benefits not quantified in PROMOD IV, including competitiveness, long-run resource cost advantages, reliability, and emissions. Testimony was submitted to the Public Service Commission of Wisconsin, which approved the line.

- **Transmission Investments and Congestion**. Worked with executives and board of an independent transmission company to develop a metric indicating congestion-related benefits provided by its transmission investments and operations.

- **Analysis of Transmission Constraints and Solutions**. For a large, geographically diverse group of clients, performed an in-depth study identifying the major transmission bottlenecks in the Western and Eastern Interconnections, and evaluating potential solutions to the bottlenecks. Worked with transmission engineers from multiple organizations to refine the data in a load flow model and a security-constrained, unit commitment and dispatch model for each interconnection. Ran 12-year, LMP-based market simulations using GE-MAPS across multiple scenarios and quantified congestion costs on major constraints. Collaborated with engineers to design potential transmission (and generation) solutions. Evaluated the benefits and costs of candidate solutions and identified several highly economic major transmission projects.

- **Merchant Transmission Impacts**. For a merchant transmission company, used GE-MAPS to analyze the effects of the Cross Sound Cable on energy prices in Connecticut and Long Island.
- **Security-Constrained Unit Commitment and Dispatch Model Calibration**. For a Midwestern utility, calibrated their PROMOD IV model, focusing on LMPs, unit commitment, flows, and transmission constraints. Helped client to understand their model's shortcomings and identify improvement opportunities. Also assisted with initial assessments of FTRs in preparation for its submission of nominations in MISO's first allocation of FTRs.
- **Model Evaluation**. Led an internal Brattle evaluation of commercially available transmission and market simulation models. Interviewed vendors and users of PROMOD IV, Gridview, DAYZER, and other models. Intensively tested each model. Evaluated accuracy of model algorithms (e.g., LMP, losses, unit commitment) and ability to calibrate models with backcasts using actual RTO data.

Integrated Resource Planning (IRP)

- **Resource Planning in Hawaii**. Assisted the Hawaiian Electric Companies in developing its Power Supply Improvement Plan, filed April 2016. Our work addressed how to maintain system security as renewable penetration increases toward 100% and displaces traditional synchronous generation. Solutions involved defining technology-neutral requirements that may be met by demand response, distributed resources, and new technologies as well as traditional resources.
- **IRP in Connecticut (for the 2008, 2009, 2010, 2012, and 2014 Plans)**. For the two major utilities in CT and the CT Dept. of Energy and Environmental Protection (DEEP), led the analysis for five successive integrated resource plans. Plans involved projecting 10-year Base Case outlooks for resource adequacy, customer costs, emissions, and RPS compliance; developing alternative market scenarios; and evaluating resource procurement strategies focused on energy efficiency, renewables, and traditional sources. Used an integrated modeling system that simulated the New England locational energy market (with the DAYZER model), the Forward Capacity Market, REC markets, and suppliers' likely investment/retirement decisions. Addressed electricity supply risks, natural gas

supply into New England, RPS standards, environmental regulations, transmission planning, emerging technologies, and energy security. Solicited input from stakeholders. Provided oral testimony before the DEEP.

- **Contingency Plan for Indian Point Nuclear Retirement**. For the New York Department of Public Service (DPS), assisted in developing contingency plans for maintaining reliability if the Indian Point nuclear plant were to retire. Evaluated generation and transmission proposals along three dimensions: their reliability contribution, viability for completion by 2016, and the net present value of costs. The work involved partnering with engineering sub-contractors, running GE-MAPS and a capacity market model, and providing insights to DPS staff.
- **Analysis of Potential Retirements to Inform Transmission Planning**. For a large utility in Eastern PJM, analyzed the potential economic retirement of each coal unit in PJM under a range of scenarios regarding climate legislation, legislation requiring mercury controls, and various capacity price trajectories.
- **Resource Planning in Wisconsin**. For a utility considering constructing new capacity, demonstrated the need to consider locational marginal pricing, gas price uncertainty, and potential CO_2 liabilities. Guided client to look beyond building a large coal plant. Led them to mitigate exposures, preserve options, and achieve nearly the lowest expected cost by pursuing a series of smaller projects, including a promising cogeneration application at a location with persistently high LMPs. Conducted interviews and facilitated discussions with senior executives to help the client gain support internally and begin to prepare for regulatory communications.

Demand Response (DR) Resource Potential and Market Impact

- **ERCOT DR Potential Study**. For ERCOT, estimated the market size for DR by end-user segment based on interviews with curtailment service providers and utilities and informed by penetration levels achieved in other regions. Presented findings to the Public Utility Commission of Texas at a workshop on resource adequacy.
- **DR Potential Study**. For an Eastern ISO, analyzed the biggest, most cost-effective opportunities for DR and price responsive demand in the footprint, and what the ISO could do to facilitate them. For each segment of the market, identified the ISO and/or state and utility initiatives that would be needed to develop various levels of capacity and energy market response. Also estimated the potential and cost characteristics for each segment. Interviewed numerous curtailment service providers and ISO personnel.
- **Wholesale Market Impacts of Price-Responsive Demand (PRD)**. For NYISO, evaluated the potential effects of widespread implementation of dynamic retail rates. Utilized the PRISM model to estimate effects on consumption by customer class, applied empirically-based elasticities to hourly differences between flat retail

rates and projected dynamic retail rates. Utilized the DAYZER model to estimate the effects of load changes on energy costs and prices.

- **Energy Market Impacts of DR**. For PJM and the Mid-Atlantic Distributed Resources Initiative (sponsored by five state commissions), quantified the market impacts and customer benefits of DR programs. Used a simulation-based approach to quantify the impact that a three percent reduction of peak loads during the top 20 five-hour blocks would have had in 2005 and under a variety of alternative market conditions. Utilized the DAYZER market simulation model, which we calibrated to represent the PJM market using data provided by PJM and public sources. Results were presented in multiple forums and cited widely, including by several utilities in their filings with state commissions regarding investment in advanced metering infrastructure and implementation of DR programs.
- **Value of DR Investments**. For Pepco Holdings, Inc., evaluated its proposed DR-enabling investments in advanced metering infrastructure and its efficiency programs. Estimated reductions in peak load that would be realized from dynamic pricing, direct load control, and efficiency. Built on the Brattle-PJM-MADRI study to estimate short-term energy market price impacts and addressed long-run equilibrium offsetting effects through supplier response scenarios. Estimated capacity price impacts and resource cost savings over time. Submitted a whitepaper to DE, NJ, MD, and DC commissions. Presented findings to DE Commission.

Gas-Electric Coordination

- **Gas Pipeline Investment for Electricity.** For the Maine Office of Public Advocate, co-sponsored testimony regarding the reliability and economic impacts if the Maine PUC signed long-term contracts for electricity customers to pay for new gas pipeline capacity into New England. Analyzed other experts' reports and provided a framework for evaluating whether such procurements would be in the public interest, considering their costs and benefits vs. alternatives.
- **Gas Pipeline Investment for Electricity.** For the Massachusetts Attorney General's office, provided input for their comments in the Massachusetts Department of Public Utilities' docket investigating whether and how new natural gas delivery capacity should be added to the New England market.
- **Fuel Adequacy and Other Winter Reliability Challenges**. For an ISO, co-authored a report assessing the risks of winter reliability events due to inadequate fuel, inadequate weatherization, and other factors affecting resource availability in the winter. Evaluated solutions being pursued by other ISOs. Proposed changes to resource adequacy requirements and energy market design to mitigate the risks.
- **Gas-Electric Reliability Challenges in the Midcontinent**. For MISO, provided a PowerPoint report assessing future gas-electric challenges as gas reliance increases.

Characterized solutions from other ISOs. Provided inputs on the cost of firm pipeline gas vs. the cost and operational characteristics of dual-fuel capability.

RTO Participation and Configuration

- **Market Impacts of RTO Seams**. For a consortium of utilities, submitted written testimony to the FERC analyzing the financial and operational impact of the MISO-PJM seam on Michigan and Wisconsin. Evaluated economic hurdles across RTO seams and assessed the effectiveness of inter-RTO coordination efforts underway. Collaborated with MISO staff to leverage their PROMOD IV model to simulate electricity markets under alternative RTO configurations.
- **Analysis of RTO Seams**. For a Wisconsin utility in a proceeding before the FERC, assisted expert witness on (1) MISO and PJM's real-time inter-RTO coordination process, and (2) the economic benefit of implementing a full joint-and-common market. Analyzed lack of convergence between MISO's and PJM's energy prices and shadow prices on reciprocal coordinated flow gates.
- **RTO Participation**. For an integrated Midwest utility, advised client on alternative RTO choices. Used GE-MAPS to model the transmission system and wholesale markets under various scenarios. Presented findings to senior management. Subsequently, in support of testimonies submitted to two state commissions, quantified the benefits and costs of RTO membership on customers, considering energy costs, FTR revenues, and wheeling revenues.

Energy Litigation

- **Demand Response Arbitration.** Provided expert testimony on behalf of a client that had acquired a demand response company and alleged that the company had overstated its demand response capacity and technical capabilities. Analyzed discovery materials including detailed demand response data to assess the magnitude of alleged overstatements. Calculated damages primarily based on a fair market valuation of the company with and without alleged overstatements. Provided deposition, expert report, and oral testimony before the American Arbitration Association (non-public).
- **Contract Damages.** For the California Department of Water Resources and the California Attorney General's office, supported expert providing testimony on damages resulting from an electricity supplier's alleged breaches of a power purchase agreement. Analyzed two years of hourly data on energy deliveries, market prices, ISO charges, and invoice charges to identify and evaluate performance violations and invoice overcharges. Assisted counsel in developing the theory of the case and provided general litigation support in preparation for and during arbitration. Resulted in successful award for client.

- **Contract Damages**. For the same client described above, supported expert providing testimony in arbitration regarding the supplier's alleged breaches in which its scheduled deliveries were not deliverable due to transmission congestion. Quantified damages and demonstrated the predictability of congestion, which the supplier was allegedly supposed to avoid in its choice of delivery points.
- **Contract Termination Payment**. For an independent power producer, supported expert testimony on damages from the termination of a long-term tolling contract for a gas-fired power plant in PJM, involving power market forecasting, financial valuation techniques, and a detailed assessment of the plant's costs and operating characteristics. Prepared witness for arbitration and assisted counsel in deposing and cross-examining opposing experts. Resulted in resounding victory for client.

Tariff and Rate Design

- **Wholesale Rates.** On behalf of a G&T co-op in the Western U.S., provided testimony regarding its wholesale rates, which are contested by member co-ops. Analyzed the G&T co-op's cost of service and its marginal cost of meeting customers' energy and peak demand requirements.
- **Transmission Tariffs**. For a merchant generating company participating in FERC hearings on developing a Long Term Transmission Pricing Structure, helped lead a coalition of stakeholders to develop a position on how to eliminate pancaked transmission rates while allowing transmission owners to continue to earn their allowed rate of return. Analyzed and presented the implications of various transmission pricing proposals on system efficiency, incentives for new investment, and customer rates throughout the MISO-PJM footprint.
- **Retail Rate Riders**. For a traditionally regulated Midwest utility, helped general counsel to evaluate and support legislation, and propose commission rules addressing rate riders for fuel and purchased power and the costs of complying with environmental regulations. Performed research on rate riders in other states; drafted proposed rules and tariff riders for client.
- **Rate Filings**. For a traditionally regulated Midwest utility, assisted counsel in preparing for a rate case. Helped draft testimonies regarding off-system sales margins and the cost of fuel.

Business Strategy

- **Preparing a Gentailer for a Transformed Wholesale Market Design.** Supported a gentailer in Alberta to prepare its generation and retail businesses for the implementation of a capacity market.
- **Evaluation of Cogeneration Venture**. For an unregulated division of a utility, evaluated a venture to build and operate cogeneration facilities. Estimated the market size and potential pricing, and assessed the client's capabilities for delivering such services. Analyzed the target customer base in detail; performed technical cost analysis for building and operating cogeneration plants; analyzed retail/default rate structures against which new cogeneration would have to compete. Senior management followed our recommendations to shut down the venture.
- **Strategic Sourcing**. For a large, diversified manufacturer, coordinated a cross-business unit client team to reengineer processes for procuring electricity, natural gas, and demand-side management services. Worked with executives to establish goals. Gathered data on energy usage patterns, costs, and contracts across hundreds of facilities. Interviewed energy managers, plant managers, and executives. Analyzed potential suppliers. Helped draft RFPs and develop negotiating strategy. Designed internal organizational structure (incorporating outsourced service providers) for managing energy procurement on an ongoing basis.
- **M&A Advisory**. For a European utility aiming to enter the U.S. markets and enhance its trading capability, evaluated acquisition targets. Assessed potential targets' capabilities and their value versus stock price. Reviewed experiences of acquirers in other M&A transactions. Advised client against an acquisition, just when the market was peaking (just prior to collapse).
- **Marketing Strategy**. For a power equipment manufacturer, identified the most attractive target customers and joint-venture candidates for plant maintenance services. Evaluated the cost structure and equipment mix of candidates using FERC data and proprietary data. Estimated the value client could bring to each customer. Worked with company president to translate findings into a marketing strategy.
- **Distributed Generation (DG) Market Assessment**. For the unregulated division of a major utility, performed a market assessment of DG technologies. Projected future market sizes by market segments in the U.S.
- **Fuel Cells**. For a European fuel cell component manufacturer, acted as a technology and electricity market advisor for a larger consulting team developing a market entry strategy in the U.S.

TESTIMONY and REGULATORY FILINGS

Before the Indiana General Assembly 21st Century Energy Policy Development Task Force, "Electricity Transmission Basics," on behalf of the Indiana Energy Association, October 17, 2019.

Before the Federal Energy Regulatory Commission, Docket No. ER19-105-000, Periodic Review of Variable Resource Requirement Curve Shape and Key Parameters, "Affidavit of Samuel A. Newell, John H. Hagerty, and Sang H. Gang on Behalf of PJM Interconnection, L.L.C." regarding the Cost of New Entry, accompanied by report, *PJM Cost of New Entry Combustion Turbines and Combined-Cycle Plants with June 1, 2022 Online Date*, October 12, 2018.

Before the Federal Energy Regulatory Commission, Docket No. ER19-105-000, Periodic Review of Variable Resource Requirement Curve Shape and Key Parameters, "Affidavit of Dr. Samuel A. Newell and David Luke Oates on behalf of PJM Interconnection, L.L.C," regarding the Variable Resource Requirement Curve Shape, accompanied by report, *Fourth Review of PJM's Variable Resource Requirement Curve*, October 12, 2018.

Before the Federal Energy Regulatory Commission, Docket Nos. EL16-49-000, ER18-1314-000, ER18-1314-001, EL18-178-000 (Consolidated), Affidavit of Kathleen Spees and Samuel A. Newell Regarding the Need for a Self-Supply Exemption from Minimum Offer Price and Other Policy Supported Resource Rules on behalf of Dominion Energy Services, Inc. and Virginia Electric and Power Company, October 2, 2018.

Before the Federal Energy Regulatory Commission, Docket Nos. EL17-32-000 and EL17-36-000, Prefiled Comments of Samuel A. Newell, Kathleen Spees, and Yingxia Yang on behalf on behalf of the Natural Resources Defense Council: "Opportunities to More Efficiently Meet Seasonal Capacity Needs in PJM," April 15, 2018; presented oral testimony on the Seasonality Panel at FERC's Seasonal Capacity Technical Conference on April 24, 2018.

Before the Federal Energy Regulatory Commission, Docket No. EL18-34-000, Samuel A. Newell, Pablo A. Ruiz, and Rebecca C. Carroll, "Evaluation of PJM's Fast-Start Pricing Proposal," report prepared for NextEra Energy Resources and attached to *Reply Brief of Joint Commenters*, March 14, 2018.

Before the New Hampshire Site Evaluation Committee, Docket No. 2015-06, oral testimony and cross examination on the electricity market impacts of the proposed Northern Pass Transmission Project, October 26-27, 2017.

Before the Federal Energy Regulatory Commission, Docket No. AD17-11-000, Prefiled Comments of Samuel A. Newell re "Reconciling Wholesale Competitive Markets with State Polices," April 25, 2017; and oral testimony on Industry Expert Panel at the Technical Conference on May 2, 2017.

Before the New Hampshire Site Evaluation Committee, Docket No. 2015-06, Prefiled Supplemental Testimony of Samuel Newell and Jurgen Weiss on behalf of the New Hampshire Counsel for the Public, with attached report, "Electricity Market Impacts of the Proposed Northern Pass Transmission Project--Supplemental Report," April 17, 2017.

Before the Federal Energy Regulatory Commission, Docket No. ER17-284-000, filed "Response of Dr. Samuel A. Newell, Dr. Kathleen Spees, and Dr. David Luke Oates on behalf of Midcontinent Independent System Operator Regarding the Competitive Retail Solution," January 13, 2017.

Before the New Hampshire Site Evaluation Committee, Docket No. 2015-06, Prefiled Direct Testimony of Samuel Newell and Jurgen Weiss on behalf of the New Hampshire Counsel for the Public, with attached report, "Electricity Market Impacts of the Proposed Northern Pass Transmission Project," December 30, 2016.

Before the Federal Energy Regulatory Commission, Docket No. ER17-284-000, filed "Testimony of Dr. Samuel A. Newell, Dr. Kathleen Spees, and Dr. David Luke Oates on behalf of Midcontinent Independent System Operator Regarding the Competitive Retail Solution," November 1, 2016.

"Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades," Appendix 1 to Comparative Evaluation of Alternating Current Transmission Upgrade Alternatives, Trial Staff Final Report, *Proceeding on Motion of the Commission to Examine Alternating Current Transmission Upgrades*, New York State Department of Public Service, Matter No. 12-02457, Case No. 12-T-0502, September 22, 2015. Presented to NYISO and DPS Staff at the Technical Conference, Albany, NY, October 8, 2015.

Before the Maine Public Utilities Commission, Docket No. 2014-00071, filed "Testimony of Dr. Samuel A. Newell and Matthew P. O'Loughlin on Behalf of the Maine Office of the Public Advocate, Comments on LEI's June 2015 Report and Recommendations for a Regional Analysis," November 18, 2015.

Before the Federal Energy Regulatory Commission, Docket No. ER14-2940-000, filed "Response of Dr. Samuel A. Newell and Dr. Kathleen Spees on Behalf of PJM Interconnection, LLC Regarding Variable Resource Requirement Curve," for use in PJM's capacity market, November 5, 2014.

Before the Federal Energy Regulatory Commission, Docket No. ER15-68-000, filed "Affidavit of Dr. Samuel A. Newell on behalf of PJM Interconnection, LLC," regarding the Cost of New Entry for use in PJM's Minimum Offer Price Rule, October 9, 2014.

Before the Texas House of Representatives Environmental Regulation Committee, Hearing on the Environmental Protection Agency's Newly Proposed Clean Power Plan and Potential Impact on Texas, invited by Committee Chair to present, "EPA's Clean Power Plan: Basics of the Rule, and Implications for Texas," Austin, TX, September 29, 2014.

Before the Federal Energy Regulatory Commission, Docket No. ER14-2940-000, filed "Affidavit of Dr. Samuel A. Newell and Mr. Christopher D. Ungate on Behalf of PJM Interconnection, LLC," regarding the Cost of New Entry for use in PJM's capacity market, September 25, 2014.

Before the Federal Energy Regulatory Commission, Docket No. ER14-2940-000, filed "Affidavit of Dr. Samuel A. Newell and Dr. Kathleen Spees on Behalf of PJM Interconnection, LLC Regarding Periodic Review of Variable Resource Requirement Curve Shape and Key Parameters," September 25, 2014.

Before the Public Utilities Commission of the State of Colorado, Proceeding No. 13F-0145E, "Answer Testimony and Exhibits of Samuel A. Newell on Behalf of Tri-State Generation and Transmission

Association, Inc.," regarding an analysis of complaining parties' responses to Tri-State Generation and Transmission Association, Inc.'s Third Set of Data Requests, Interrogatory, September 10, 2014.

Before the Maine Public Utilities Commission, Docket No. 2014-00071, "Testimony of Dr. Samuel A. Newell and Matthew P. O'Loughlin on Behalf of the Maine Office of the Public Advocate, Analysis of the Maine Energy Cost Reduction Act in New England Gas and Electricity Markets," July 11, 2014.

Before the Federal Energy Regulatory Commission, Docket No. ER14-1639-000, filed "Testimony of Dr. Samuel A. Newell and Dr. Kathleen Spees on behalf of ISO New England Inc. Regarding a Forward Capacity Market Demand Curve," April 1, 2014.

Before the Federal Energy Regulatory Commission, Docket No. ER14-1639-000, filed "Testimony of Dr. Samuel A. Newell and Mr. Christopher D. Ungate on Behalf of ISO New England Inc. Regarding the Net Cost of New Entry for The Forward Capacity Market Demand Curve," April 1, 2014.

Before the Federal Energy Regulatory Commission, Docket No. ER14-616-000, filed "Affidavit of Dr. Samuel A. Newell on Behalf of ISO New England Inc.," and accompanying "2013 Offer Review Trigger Prices Study," regarding the Minimum Offer Price Rule new capacity resources in capacity auctions, December 13, 2013.

Before the American Arbitration Association, provided expert testimony (deposition, written report, and oral testimony at hearing) in a dispute involving the acquisition of a demand response company, July-November, 2013. (Non-public).

Before the Public Utility Commission of Texas, at a workshop on Project No. 40000, presented "Report On ORDC B+ Economic Equilibrium Planning Reserve Margin Estimates Prepared By The Brattle Group," on behalf of The Electric Reliability Council of Texas (ERCOT), June 25, 2013. Subsequently filed additional comments, "Additional ORDC B+ Economic Equilibrium Planning Reserve Margin Estimates," July 29, 2013.

Before the Federal Energy Regulatory Commission, Docket No. ER13-535-000, filed "Affidavit of Dr. Samuel A. Newell on Behalf of the 'Competitive Markets Coalition' Group Of Generating Companies," supporting PJM's proposed tariff revisions to change certain terms regarding the Minimum Offer Price Rule in the Reliability Pricing Model, December 28, 2012.

Before the Federal Energy Regulatory Commission, Docket No. ER12-513-000, filed "Affidavit of Dr. Samuel A. Newell on Behalf of PJM Interconnection, LLC," in support of PJM's Settlement Agreement regarding the Cost of New Entry for use in PJM's capacity market, November 21, 2012.

Before the Texas House of Representatives State Affairs Committee, Hearing on the issue of resource adequacy in the Texas electricity market, presented "The Resource Adequacy Challenge in ERCOT," on behalf of The Electric Reliability Council of Texas, October 24, 2012.

Before The Public Utility Commission of Texas, at a workshop on Project No. 40480, presented "Resource Adequacy in ERCOT: 'Composite' Policy Options," and "Estimate of DR Potential in ERCOT" on behalf of The Electric Reliability Council of Texas (ERCOT), October 25, 2012.

Before The Public Utility Commission of Texas, at a workshop on Project No. 40480, presented "ERCOT Investment Incentives and Resource Adequacy," September 6, 2012.

Before The Public Utility Commission of Texas, at a workshop on Project No. 40480, presented "Summary of Brattle's Study on ERCOT Investment Incentives and Resource Adequacy," July 27, 2012.

Before the Federal Energy Regulatory Commission, Docket No. ER12-___-000, Affidavit of Dr. Samuel A. Newell on Behalf of SIG Energy, LLLP, March 29, 2012, Confidential Exhibit A in Complaint of Sig Energy, LLLP, SIG Energy, LLLP v. California Independent System Operator Corporation, Docket No. EL 12-___-000, filed April 4, 2012 (Public version, confidential information removed).

Before the Federal Energy Regulatory Commission, Docket No. ER12-13-000, filed "Response of Dr. Samuel A. Newell and Dr. Kathleen Spees on Behalf of PJM Interconnection, LLC," regarding the Cost of New Entry for use in PJM's capacity market, January 13, 2012.

Before the Federal Energy Regulatory Commission, Docket No. ER12-13-000, Affidavit of Dr. Samuel A. Newell on Behalf of PJM Interconnection, LLC, re: the Cost of New Entry Estimates for Delivery Year 2015/16 in PJM's Reliability Pricing Model, filed December 1, 2011.

Before the Federal Energy Regulatory Commission, Docket Nos. ER11-4069 and ER11-4070, Direct testimony of Johannes Pfeifenberger and Samuel Newell on behalf of the RITELine Companies, re: the public policy, congestion relief, and economic benefits of the RITELine Transmission Project, filed July 18, 2011.

Before the Federal Energy Regulatory Commission, Docket No. No. EL11-13-000, Direct testimony of Johannes Pfeifenberger and Samuel Newell on behalf of The AWC Companies re: the public policy, reliability, congestion relief, and economic benefits of the Atlantic Wind Connection Project, filed December 20, 2010.

"Economic Evaluation of Alternative Demand Response Compensation Options," whitepaper filed by ISO-NE in its comments on FERC's Supplemental Notice of Proposed Rulemaking in Docket No. RM10-17-000, October 13, 2010 (with K. Madjarov).

Before the Federal Energy Regulatory Commission, Docket No. RM10-17-000, Filed Comments re: Supplemental Notice of Proposed Rulemaking and September 13, 2010 Technical Conference, October 5, 2010 (with K. Spees and P. Hanser).

Before the Federal Energy Regulatory Commission, Docket No. RM10-17-000, Filed Comments re: Notice of Proposed Rulemaking regarding wholesale compensation of demand response, May 13, 2010 (with K. Spees and P. Hanser).

Before the Connecticut Department of Public Utility Control, provided oral testimony to support the 2010 "Integrated Resource Plan for Connecticut" (see below), June 2010.

2010 "Integrated Resource Plan for Connecticut," report co-submitted with The Connecticut Light & Power Company and The United Illuminating Company to the Connecticut Energy Advisory Board, January 4, 2010. Presented to the Connecticut Energy Advisory Board January 8, 2010.

"Dynamic Pricing: Potential Wholesale Market Benefits in New York State," lead authors: Samuel Newell and Ahmad Faruqui at The Brattle Group, with contributors Michael Swider, Christopher Brown, Donna Pratt, Arvind Jaggi and Randy Bowers at the New York Independent System Operator, submitted as "Supplemental Comments of the NYISO Inc. on the Proposed Framework for the Benefit-Cost Analysis of Advanced Metering Infrastructure," in State of New York Public Service Commission Case 09-M-0074, December 17, 2009.

Before the Connecticut Department of Public Utility Control, provided oral testimony to support the 2009 "Integrated Resource Plan for Connecticut" (see below), June 30, 2009.

2009 "Integrated Resource Plan for Connecticut," report co-submitted with The Connecticut Light & Power Company and The United Illuminating Company to the Connecticut Energy Advisory Board, January 1, 2009.

"Informational Filing of the Internal Market Monitoring Unit's Report Analyzing the Operations and Effectiveness of the Forward Capacity Market," prepared by Dave LaPlante and Hung-po Chao of ISO-NE with Sam Newell, Metin Celebi, and Attila Hajos of The Brattle Group, filed with FERC on June 5, 2009 under Docket No. ER09-1282-000.

Before the Connecticut Department of Public Utility Control, provided oral testimony to support the 2008 "Integrated Resource Plan for Connecticut" and "Supplemental Reports" (see below), September 22, 2008.

"Integrated Resource Plan for Connecticut," co-submitted with The Connecticut Light & Power Company and The United Illuminating Company to the Connecticut Energy Advisory Board; co-authored with M. Chupka, A. Faruqui, and D. Murphy, January 2, 2008. Supplemental Report co-submitted with The Connecticut Light & Power Company and The United Illuminating Company to the Connecticut Department of Utility Control; co-authored with M. Chupka, August 1, 2008.

"Quantifying Customer Benefits from Reductions in Critical Peak Loads from PHI's Proposed Demand-Side Management Programs," whitepaper by Samuel A. Newell and Ahmad Faruqui filed by Pepco Holdings, Inc. with the Public Utility Commissions of Delaware (Docket No. 07-28, 9/27/2007), Maryland (Case No. 9111, filed 12/21/07), New Jersey (BPU Docket No. EO07110881, filed 11/19/07), and Washington, DC (Formal Case No. 1056, filed 10/1/07). Presented orally to the Public Utility Commission of Delaware, September 5, 2007.

Before the Public Service Commission of Wisconsin, Docket 137-CE-149, "Planning Analysis of the Paddock-Rockdale Project," report by American Transmission Company re: transmission cost-benefit analysis, April 5, 2007 (with J.P. Pfeifenberger and others).

Prepared Supplemental Testimony on Behalf of the Michigan Utilities before the Federal Energy Regulatory Commission, Docket No. ER04-718-000 et al., re: Financial Impact of ComEd's and AEP's RTO Choices, December 21, 2004 (with J. P. Pfeifenberger).

Prepared Direct and Answering Testimony on Behalf of the Michigan-Wisconsin Utilities before the Federal Energy Regulatory Commission, Docket No. ER04-375-002 et al., re: Financial Impact of ComEd's and AEP's RTO Choices on Michigan and Wisconsin, September 15, 2004 (with J.P. Pfeifenberger).

Declaration on Behalf of the Michigan-Wisconsin Utilities before the Federal Energy Regulatory Commission, Docket No. ER04-375-002 et al., re: Financial Impact of ComEd's and AEP's RTO Choices on Michigan and Wisconsin, August 13, 2004 (with J.P. Pfeifenberger).

PUBLICATIONS

Estimation of the Market Equilibrium and Economically Optimal Reserve Margins for the ERCOT Region, 2018 Update, Final Draft, prepared for the Electric Reliability Council of Texas, December 20, 2018 (with R. Carroll, A. Kaluzhny, K. Spees, K. Carden, N. Wintermantel, and A. Krasny).

Harmonizing Environmental Policies with Competitive Markets: Using Wholesale Power Markets to Meet State and Customer Demand for a Cleaner Electricity Grid More Cost Effectively, discussion paper, July 2018 (with K. Spees, J. Pfeifenberger, and J. Chang).

Fourth Review of PJM's Variable Resource Requirement Curve, report prepared for PJM Interconnection LLC for submission to FERC and PJM stakeholders, April 16, 2018 (with J. Pfeifenberger, K. Spees, and others).

PJM Cost of New Entry Combustion Turbines and Combined-Cycle Plants with June 1, 2022 Online Date, report prepared for PJM Interconnection LLC for submission to FERC and PJM stakeholders, April 19, 2018 (with J. Michael Hagerty, J. Pfeifenberger, S. Gang of Sargent & Lundy, and others).

Evaluation of the DOE's Proposed Grid Resiliency Pricing Rule, white paper prepared for NextEra Energy Resources, October 23, 2017 (with M. Celebi, J. Chang, M. Chupka, and I. Shavel), available at http://www.brattle.com/system/publications/pdfs/000/005/530/original/Evaluation_of_the_DOE's_Proposed_Grid_Resiliency_Pricing_Rule.pdf?1509064658.

Near Term Reliability Auctions in the NEM: Lessons from International Jurisdictions, report prepared for the Australian Energy Market Operator, August 23, 2017 (with K. Spees, D.L. Oates, T. Brown, N. Lessem, D. Jang, and J. Imon Pedtke).

Pricing Carbon into NYISO's Wholesale Energy Market to Support New York's Decarbonization Goals, whitepaper prepared for the New York Independent System Operator, August 11, 2017 (with R. Lueken, J. Weiss, K. Spees, P. Donohoo-Vallett, and T. Lee), available at http://www.nyiso.com/public/webdocs/markets_operations/documents/Studies_and_Reports/Studies/Market_Studies/Pricing_Carbon_into_NYISOs_Wholesale_Energy_Market.pdf.

"How wholesale power markets and state environmental Policies can work together," *Utility Dive*, July 10, 2017 (with J. Pfeifenberger, J. Chang, and K. Spees), available at http://www.utilitydive.com/news/how-wholesale-power-markets-and-state-environmental-policies-can-work-toget/446715/.

Market Power Mitigation Mechanisms for the Wholesale Electricity Market in Western Australia, whitepaper prepared for the Public Utilities Office in the Government of Western Australia's Department of Finance, September 1, 2016 (with T. Brown, W. Graf, J. Reitzes, H. Trewn, and K. Van Horn).

Western Australia's Transition to a Competitive Capacity Auction, report prepared for Enernoc, January 29, 2016 (with K. Spees and C. McIntyre).

Enhancing the Efficiency of Resource Adequacy Planning and Procurements in the Midcontinent ISO Footprint—Options for MISO, Utilities, and States, report prepared for NRG, November 9, 2015 (with K. Spees and R. Lueken).

International Review of Demand Response Mechanisms, report prepared for Australian Energy Market Commission, October 2015 (with T. Brown, K. Spees, and D.L. Oates).

Resource Adequacy in Western Australia — Alternatives to the Reserves Capacity Mechanism, report prepared for EnerNOC, Inc., August 2014 (with K. Spees).

Third Triennial Review of PJM's Variable Resource Requirement Curve, report prepared for PJM Interconnection, LLC, May 15, 2014 (with J. Pfeifenberger, K. Spees, A. Murray, and I. Karkatsouli).

Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM, report prepared for PJM Interconnection, LLC, May 15, 2014 (with M. Hagerty, K. Spees, J. Pfeifenberger, Q. Liao, and with C. Ungate and J. Wroble at Sargent & Lundy).

Developing a Market Vision for MISO: Supporting a Reliable and Efficient Electricity System in the Midcontinent, foundational report prepared for Midcontinent Independent System Operator, Inc., January 27, 2014 (with K. Spees and N. Powers).

Estimating the Economically Optimal Reserve Margin in ERCOT, report prepared for the Public Utilities Commission of Texas, January 2014 (with J. Pfeifenberger, K. Spees, and I. Karkatsouli).

"Capacity Markets: Lessons Learned from the First Decade," *Economics of Energy & Environmental Policy*. Vol. 2, No. 2, Fall 2013 (with J. Pfeifenberger and K. Spees).

ERCOT Investment Incentives and Resource Adequacy, report prepared for the Electric Reliability Council of Texas, June 1, 2012 (with K. Spees, J. Pfeifenberger, R. Mudge, M. DeLucia, and R. Carlton).

"Trusting Capacity Markets: does the lack of long-term pricing undermine the financing of new power plants?" *Public Utilities Fortnightly*, December 2011 (with J. Pfeifenberger).

Second Performance Assessment of PJM's Reliability Pricing Model: Market Results 2007/08 through 2014/15, report prepared for PJM Interconnection LLC, August 26, 2011 (with J. Pfeifenberger, K. Spees, and others).

Cost of New Entry Estimates for Combustion-Turbine and Combined-Cycle Plants in PJM, report prepared for PJM Interconnection LLC, August 24, 2011 (with J. Pfeifenberger, K. Spees, and others).

"Fostering economic demand response in the Midwest ISO," *Energy* 35 (2010) 1544–1552 (with A. Faruqui, A. Hajos, and R.M. Hledik).

"DR Distortion: Are Subsidies the Best Way to Achieve Smart Grid Goals?" *Public Utilities Fortnightly*, November 2010.

Midwest ISO's Resource Adequacy Construct: An Evaluation of Market Design Elements, report prepared for MISO, January 2010 (with K. Spees and A. Hajos).

Demand Response in the Midwest ISO: An Evaluation of Wholesale Market Design, report prepared for MISO, January 2010 (with A. Hajos).

Cost-Benefit Analysis of Replacing the NYISO's Existing ICAP Market with a Forward Capacity Market, whitepaper written for the NYISO and submitted to stakeholders, June 15, 2009 (with A. Bhattacharyya and K. Madjarov).

Fostering Economic Demand Response in the Midwest ISO, whitepaper written for MISO, December 30, 2008 (with R. Earle and A. Faruqui).

Review of PJM's Reliability Pricing Model (RPM), report prepared for PJM Interconnection LLC for submission to FERC and PJM stakeholders, June 30, 2008 (with J. Pfeifenberger and others).

"Reviving Integrated Resource Planning for Electric Utilities: New Challenges and Innovative Approaches," *Energy*, Vol. 1, 2008, The Brattle Group (with M. Chupka and D. Murphy).

Enhancing Midwest ISO's Market Rules to Advance Demand Response, report written for MISO, March 12, 2008 (with R. Earle).

"The Power of Five Percent," *The Electricity Journal*, October 2007 (with A. Faruqui, R. Hledik, and J. Pfeifenberger).

Quantifying Customer Benefits from Reductions in Critical Peak Loads from PHI's Proposed Demand-Side Management Programs, whitepaper prepared for Pepco Holdings, Inc., September 21, 2007 (with A. Faruqui).

Review of PJM's Market Power Mitigation Practices in Comparison to Other Organized Electricity Markets, Report prepared for PJM Interconnection LLC, September 14, 2007 (with P. Fox-Penner, J. Pfeifenberger, J. Reitzes, and others).

"Valuing Demand-Response Benefits in Eastern PJM," *Public Utilities Fortnightly*, March 2007 (with J. Pfeifenberger and F. Felder).

Quantifying Demand Response Benefits in PJM, study report prepared for PJM Interconnection, LLC and the Mid-Atlantic Distributed Resources Initiative, January 29, 2007 (with F. Felder).

"Modeling Power Markets: Uses and Abuses of Locational Market Simulation Models," *Energy*, Vol. 2, 2006, The Brattle Group (with J. Pfeifenberger).

"Innovative Regulatory Models to Address Environmental Compliance Costs in the Utility Industry," October 2005 Newsletter, American Bar Association, Section on Environment, Energy, and Resources; Vol. 3 No. 1 (with J. Pfeifenberger).

PRESENTATIONS

"Pollution Pricing in the Power Sector: Market-Friendly Tools for Incorporating Public Policy," presented to GCPA Spring Conference, Houston, TX, April 16, 2019.

"The Transformation of the Power Sector to Clean Energy: Economic and Reliability Challenges," keynote address to the Power Engineers 4th Annual Power Symposium, Weehawken, NJ, April 4, 2019.

"Market Design for Winter Energy Security in New England: Further Discussion of Options," presented to The New England Power Pool Markets Committee on behalf of NextEra Energy Resources, Westborough, MA, February 6, 2019 (with D.L. Oates and P. Ruiz).

"Market Design for Winter Energy Security in New England: Discussion of Options," presented to The New England Power Pool Markets Committee on behalf of NextEra Energy Resources, Westborough, MA, January 9, 2019 (with D.L. Oates).

"Market Equilibrium Reserve Margin in ERCOT," presented to Power Markets Today webinar, "A Post Summer Check-in of ERCOT's Market," October 31, 2018.

"Carbon Pricing in NYISO's Wholesale Energy Market, and Applicability to Multi-State RTO markets," presented to Raab Policy Roundtable, May 23, 2018; presented to the Energy Bar Association, 2018 EBA Energizer: Pricing Carbon in Energy Markets, June 5, 2018; presented to Bank of America Merrill Lynch, June 25, 2018.

"Reconciling Resilience Services with Current Market Design," presented to RFF/R-Street Conference on "Economic Approaches to Understanding and Addressing Resilience in the Bulk Power System," Washington, D.C., May 30, 2018.

"System Flexibility and Renewable Energy Integration: Overview of Market Design Approaches," presented to Texas-Germany Bilateral Dialogue on Challenges and Opportunities in the Electricity Market, Austin, TX, February 26, 2018.

"Natural Gas Reliability: Understanding Fact from Fiction," panelist at the NARUC Winter Policy Summit presented to The Committee on Gas, Washington, D.C., February 13, 2018 (with A. Thapa, M. Witkin, and R. Wong).

"Carbon Pricing in Wholesale Markets: Takeaways from NYISO Carbon Charge Study," presented to Harvard Electric Policy Group, October 12, 2017.

"Pricing Carbon into NYISO's Wholesale Energy Market: Study Overview and Summary of Findings," presented to NYISO Business Issues Committee, September 12, 2017.

"Carbon Adders in Wholesale Power Markets—Preventing Leakage," panelist at Resources for the Future's workshop on carbon pricing in wholesale markets, Washington, D.C., August 2, 2017.

"Market-Based Approaches to Support States' Decarbonization Objectives," panelist at Independent Power Producers of New York (IPPNY) 2017 Spring Conference, Albany, NY, May 10, 2017.

"ERCOT's Future: A Look at the Market Using Recent History as a Guide," panelist at the Gulf Coast Power Association's Fall Conference, Austin, TX, October 4, 2016.

"The Future of Wholesale Electricity Market Design," presented to Energy Bar Association 2016 Annual Meeting & Conference, Washington, DC, June 8, 2016.

"Performance Initiatives and Fuel Assurance—What Price Mitigation?" presented to Northeast Energy Summit 2015 Panel Discussion, Boston, MA, October 27, 2015.

"PJM Capacity Auction Results and Market Fundamentals," presented to Bloomberg Analyst Briefing Webinar, September 18, 2015 (with J. Pfeifenberger and D.L. Oates).

"Energy and Capacity Market Designs: Incentives to Invest and Perform," presented to EUCI Conference, Cambridge, MA, September 1, 2015.

"Electric Infrastructure Needs to Support Bulk Power Reliability," presented to GEMI Symposium: Reliability and Security across the Energy Value Chain, The University of Houston, Houston, TX, March 11, 2015.

Before the Arizona Corporation Commission, Commission Workshop on Integrated Resource Planning, Docket No. E-00000V-13-0070, presented "Perspectives on the IRP Process: How to get the most out of IRP through a collaborative process, broad consideration of resource strategies and uncertainties, and validation or improvement through market solicitations," Phoenix, AZ, February 26, 2015.

"Resource Adequacy in Western Australia—Alternatives to the Reserve Capacity Mechanism (RCM)," presented to The Australian Institute of Energy, Perth, WA, October 9, 2014.

"Customer Participation in the Market," panelist on demand response at Gulf Coast Power Association Fall Conference, Austin, TX, September 30, 2014.

"Market Changes to Promote Fuel Adequacy—Capacity Market to Promote Fuel Adequacy," presented to INFOCAST- Northeast Energy Summit 2014 Panel Discussion, Boston, MA, September 17, 2014.

"EPA's Clean Power Plan: Basics and Implications of the Proposed CO_2 Emissions Standard on Existing Fossil Units under CAA Section 111(d)," presented to Goldman Sachs Power, Utilities, MLP and Pipeline Conference, New York, NY, August 12, 2014.

"Capacity Markets: Lessons for New England from the First Decade," presented to Restructuring Roundtable Capacity (and Energy) Market Design in New England, Boston, MA, February 28, 2014.

"The State of Things: Resource Adequacy in ERCOT," presented to INFOCAST – ERCOT Market Summit 2014 Panel Discussion, Austin, TX, February 24-26, 2014.

"Resource Adequacy in ERCOT," presented to FERC/NARUC Collaborative Winter Meeting in Washington, D.C., February 9, 2014.

"Electricity Supply Risks and Opportunities by Region," presentation and panel discussion at Power-Gen International 2013 Conference, Orlando, FL, November 13, 2013.

"Get Ready for Much Spikier Energy Prices—The Under-Appreciated Market Impacts of Displacing Generation with Demand Response," presented to the Cadwalader Energy Investor Conference, New York, NY, February 7, 2013 (with K. Spees).

"The Resource Adequacy Challenge in ERCOT," presented to The Texas Public Policy Foundation's 11th Annual Policy Orientation for legislators, Austin, TX, January 11, 2013.

"Resource Adequacy in ERCOT: the Best Market Design Depends on Reliability Objectives," presented to the Harvard Electricity Policy Group conference, Washington, D.C., December 6, 2012.

"Resource Adequacy in ERCOT," presented to the Gulf Coast Power Association Fall Conference, Austin, TX, October 2, 2012.

"Texas Resource Adequacy," presented to Power Across Texas, Austin, TX, September 21, 2012.

"Resource Adequacy and Demand Response in ERCOT," presented to the Center for the Commercialization of Electric Technologies (CCET) Summer Board Meeting, Austin, TX, August 8, 2012.

"Summary of Brattle's Study on 'ERCOT Investment Incentives and Resource Adequacy'," presented to the Texas Industrial Energy Consumers annual meeting, Austin, TX, July 18, 2012.

"Market-Based Approaches to Achieving Resource Adequacy," presentation to Energy Bar Association Northeast Chapter Annual Meeting, Philadelphia, PA, June 6, 2012.

"Fundamentals of Western Markets: Panel Discussion," WSPP's Joint EC/OC Meeting, La Costa Resort, Carlsbad, CA, February 26, 2012 (with J. Weiss).

"Integrated Resource Planning in Restructured States," presentation at EUCI conference on "Supply and Demand-Side Resource Planning in ISO/RTO Market Regimes," White Plains, NY, October 17, 2011.

"Demand Response Gets Market Prices: Now What?" NRRI teleseminar panelist, June 9, 2011.

Before the PJM Board of Directors and senior level representatives at PJM's General Session, panel member serving as an expert in demand response on behalf of Pepco Holdings, Inc., December 22, 2007.

"Resource Adequacy in New England: Interactions with RPS and RGGI," Energy in the Northeast Law Seminars International Conference, Boston, MA, October 18, 2007.

"Corporate Responsibility to Stakeholders and Criteria for Assessing Resource Options in Light of Environmental Concerns," Bonbright Electric & Natural Gas 2007 Conference, Atlanta, GA, October 3, 2007.

"Evaluating the Economic Benefits of Transmission Investments," EUCI's Cost-Effective Transmission Technology Conference, Nashville, TN, May 3, 2007 (with J. Pfeifenberger, presenter).

"Quantifying Demand Response Benefits in PJM," PowerPoint presentation to the Mid-Atlantic Distributed Resources Initiative (MADRI) Executive Committee on January 13, 2007, to the MADRI Working Group on February 6, 2007, as Webinar to the U.S. Demand Response Coordinating Council, and to the Pennsylvania Public Utility Commission staff April 27, 2007.

"Who Will Pay for Transmission," CERA Expert Interview, Cambridge, MA, January 15, 2004.

"Reliability Lessons from the Blackout; Transmission Needs in the Southwest," presented at the Transmission Management, Reliability, and Siting Workshop sponsored by Salt River Project and the University of Arizona, Phoenix, AZ, December 4, 2003.

"Application of the 'Beneficiary Pays' Concept," presented at the CERA Executive Retreat, Montreal, Canada, September 17, 2003.

JOHN MICHAEL HAGERTY

Senior Associate

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Mr. John Michael Hagerty is a Senior Associate at The Brattle Group with experience in electricity wholesale market design, transmission planning and development, renewable and climate policy analysis, and strategic planning for utility companies. Michael has worked on several analyses in support of cost of new entry (CONE) estimates for ISO-NE, PJM and the Alberta Electric System Operator (AESO). These projects included working closely with engineering consultants and stakeholders developing reference technology specifications and bottom-up cost estimates, developing enhanced approaches for calculating E&AS revenues projections, and estimating cost of capital for merchant generation plants. These projects have required extensive engagement with the client and stakeholders to develop well-supported parameters to capacity market demand curve and clearly present our analyses to stakeholders.

Mr. Hagerty received his M.S. in Technology and Policy from the Massachusetts Institute of Technology and his B.S. in Chemical Engineering from the University of Notre Dame. Prior to joining Brattle, Mr. Hagerty was a research assistant at the MIT Energy Initiative, an oil refinery process engineer at Honeywell, and a research chemist at GE Global Research.

AREAS OF EXPERTISE

- Electricity wholesale market design
- Electrification and deep decarbonization
- Renewable energy and climate policy analysis
- Transmission planning and development
- Strategic planning and long-term resource planning

EXPERIENCE

Electricity Wholesale Market Design

- **PJM Cost of New Entry Study.** For PJM in 2014 and 2018, evaluated the most recent market trends for new gas-fired generation, updated specifications of the reference resource, and updated of the Cost of New Entry (CONE) parameter. In addition, evaluated the methodology for estimating the energy margins and ancillary services revenues in the Net CONE calculation and proposed revisions and a forward-looking approach.
- **AESO Cost of New Entry Study.** For the soon-to-be implemented capacity market, evaluated the Alberta-specific drivers of new entry, technologies most recently installed, and applicable financial assumptions. Developed candidate reference

technology specifications and currently estimating bottom-up cost estimates. Evaluated pros/cons of E&AS methodology across U.S. capacity markets and proposed forward-looking approach using the best available market data in Alberta.

- **Harmonizing New York's Wholesale Energy Market and Environmental Goals through Carbon Pricing**. Worked with NYISO to: (1) develop and evaluate market design options, including mechanisms for charging emitters and allocating charges to customers, border charges to prevent leakage, and interactions with other market design and policy elements; and (2) develop a flexible model to evaluated how carbon pricing would affect market outcomes, emissions, system costs, and customer costs under a range of assumptions. Whitepaper initiated discussions with NY DPS and stakeholders. Currently supporting NYISO in detailed market design and stakeholder engagement.
- **ISO-NE Net Cost of New Entry.** For ISO New England, worked with Sargent & Lundy and stakeholders to develop estimates for the Net Cost of New Entry (Net CONE) to which the prices in the demand curve are indexed.
- **ISO-NE Offer Review Trigger Prices.** For the Internal Market Monitor in ISO New England, developed offer review trigger prices for screening for uncompetitively low offers in the Forward Capacity Market. Collaborated with Sargent & Lundy to conduct a bottom-up analysis of the costs of building and operating gas-fired generation technologies and onshore wind; also estimated the costs of energy efficiency, and demand response. For each technology, estimated the capacity payment needed to make the resource economically viable, given expected non-capacity revenues, a long-term market view, and a cost of capital. Recommendations were filed with and accepted by the Federal Energy Regulatory Commission (FERC).
- **Fuel Supply and Grid Resilience**. Evaluated the U.S. Department of Energy Notice of Proposed Rulemaking concerning fuel supply and grid resilience. Reviewed and documented most recent studies that evaluated value of resilience and approaches for developing metrics and processes for increasing system resilience.

Electrification and Deep Decarbonization

- **New England 2050 Resource Needs**: For the Coalition for Community Solar Access, we conducted a study on the requirements to meet clean energy resource deployment in New England consistent with economy-wide decarbonization targets in the region by 2050.
- **Transmission Needs in an Electrified Future:** For the WIRES Group, we estimated the scale of nationwide transmission investment that will be necessary to support

the electrification of the U.S. economy. In this analysis, we used our bLECTRIFY modeling suite to estimate the incremental annual energy demand, peak load impact, and renewable resources necessary in 2030 and 2050 to meet the rising demand across 6 U.S. regions. The modeling includes the ability to estimate hourly demand impacts of various degrees of electrification of energy end uses including transportation, space and water heating as well as at a high-level industrial processes and agriculture.

- **Electrification Cost-effectiveness:** For EPRI, we are currently developing a methodology for evaluating the cost-effectiveness of ratepayer funded electrification programs. Our research involves a review of the literature on demand-side resource cost-effectiveness tests, interviews with industry experts on cost-effectiveness and electrification, and the publication of a report summarizing the findings and key recommendations.
- **2050 Scenario Development for Offshore Wind Developer:** For a potential bidder into an offshore wind procurement in New York, we developed 2050 demand (and resulting regional price) forecasts including 8760 hourly projections of electrification related demand.
- **Electrification – Emerging Opportunities for Utility Growth:** Paper using bLECTRIFY to estimate the technical potential for electrification of transport and heating in terms of both increases of (utility) electricity sales and GHG emissions reductions. Using a transparent model of the U.S. energy system, the paper estimates that full electrification of both sectors by 2050 could double electricity sales relative to 2015 and reduce economy-wide carbon emissions by over 75% relative to 2015, making full electrification one, and perhaps the only feasible pathway to meeting economy-wide emissions reduction targets of 80% by 2050.
- **California GHG Allowance Market Analysis.** For a California utility, analyzed the near- and long-term GHG allowance prices under AB32, which included a comprehensive review of GHG emissions reductions opportunities and cost estimates and development of an integrated approach for projecting GHG allowance prices.

Renewable Energy and Climate Policy Analysis

- **Renewable Options for Massachusetts:** For the Barr Foundation, reviewed the literature on renewable resource options, synthesized most relevant results, and developed policy recommendations for policy makers in Massachusetts to consider in setting requirements for future low carbon resource procurements. Presented findings at Massachusetts Senate hearing.

- **Reliability Concerns of Clean Power Plan.** For the Advanced Energy Economy Institute, assessed the North American Electric Reliability Corporation's (NERC) initial reliability assessment of the U.S. Environmental Protection Agency's Clean Power Plan, which is designed to lower greenhouse gas emissions from existing power plants. The project involved assessing NERC's review and providing a range of options for providing reliability while complying with the Clean Power Plan.
- **Impediments for Renewable Energy Development in Nebraska.** For the Nebraska Power Review Board, analyzed the potential impediments to greater renewable energy development and provided policy recommendations to the state that wants to pursue more renewable energy development, primarily for export out of the state.
- **Regional Renewable Energy Analysis.** For the State of Connecticut, analyzed the New England renewable energy market including a detailed evaluation of short-term and long-term supply and demand balance of renewable energy in the region, an examination of the supply potential in the region and the potential effect of transmission investment choices on renewable energy development in the region and provided policy recommendations about the procurement of electric power resources for a 10-year horizon, after comparing the potential effects of future scenarios on various resource procurement possibilities.

Transmission Planning and Development

- **Benefit-Cost Analysis of Ten West Link**: For Starwood Energy, prepared testimony on the economic and policy of the Ten West Link transmission project filed by Brattle Principal Judy Chang to the Arizona Line Siting Committee and the California Public Utilities Commission.
- **Benefits of Path 15 Upgrade in California**: For DATC, prepared testimony to be filed by Brattle Principal Hannes Pfeifenberger to FERC concerning the benefits of the Path 15 Upgrade to the California electric power system.
- **Benefits of MISO MVP Project**: For ATC, prepared testimony to be filed by Brattle Principal Hannes Pfeifenberger to the Wisconsin Public Service Commission concerning the benefits of the Cardinal-Hickory Creek Project to the MISO power system and Wisconsin ratepayers.
- **Competitive Transmission Planning Processes.** For several transmission developers analyzed the scope of competitive transmission planning processes and the potential cost savings and innovations resulting from these processes. Compared the U.S. experience under FERC Order 1000 with the available experience in Canada, the U.K., and Brazil.

- **Benefits of TransWest Express:** For TransWest Express LLC, summarized the benefits of the TransWest Express transmission project to the western power system, Colorado, and the local counties for the purposes of obtaining sufficient right-of-way for the project.
- **Impacts of Northern Pass on New England Markets**: For the New Hampshire Attorney General's Office, evaluated the energy and capacity market benefits and environmental impact of the Northern Pass transmission project, a proposed HVDC transmission line linking the Canadian Province of Quebec with the New England power system.
- **Benefit-Cost Analysis of New York Transmission Upgrades**: For New York Public Service Commission, analyzed potential benefits of more than 15 proposed transmission portfolios. Benefits analysis included production cost savings, capacity resource savings, avoided reliability upgrades, and reduced costs of meeting renewable/climate goals. Each transmission portfolio analyzed both from a societal (NPV) perspective and a ratepayer perspective.
- **Quadrennial Energy Review Electricity Baseline Analysis**: For PNNL and the U.S. Department of Energy, reviewed and summarized major issues concerning infrastructure across the electric power sector and, in particular, current trends in transmission, distribution, and storage infrastructure development and planning and discussed on-going challenges to building a more reliable and efficient electric power system.
- **Developed Process for Using Scenario-based Approach for Transmission Planning.** For the Electric Reliability Council of Texas (ERCOT), developed and led ERCOT and stakeholder sessions in developing future scenarios appropriate for long-term transmission planning.
- **Evaluation of Transmission Planning and Benefits Metrics.** For The Electric Reliability Council of Texas (ERCOT), reviewed, assessed, and developed recommendations for: 1) improvements in planning process, 2) methods for evaluating the long-term costs and benefits, and 3) improvements in system simulations. These recommendations are used to develop an improved business case for transmission.
- **Transmission Planning and Benefits/Costs Analyses.** For WIRES, a trade group of transmission companies, authored a peer-reviewed whitepaper outlining the industry practices for methodologies for evaluating the benefits and costs of economic transmission projects; and present a scenario-based approach to transmission planning.

- **Benchmarking of the Impact of Regulatory Processes on Transmission Costs.** For an international transmission company, analyzed the potential impact of the differences associated with jurisdictional and regulatory process on transmission project costs.

Strategic Planning and Long-term Resource Planning

- **Scenario-based Strategic Planning for Generation and Transmission Cooperative.** For a utility, led the senior executive team and board members in developing long-range strategies for the organization, incorporating rate design principles, transmission development strategies, generation deployment, and strategies surrounding emerging technologies and employee retention, training and succession. Also working with the board and senior executives to develop specific strategic initiatives that would guide the organization.
- **Resource Planning.** For a utility in the West, guided a group of cross-functional planning group in assessing future uncertainties, developing future scenarios, developed analytical frameworks and methodologies in analyzing future resource options. Recommendations included using scenario-based and stochastic approaches in analyzing the risks associated with short-term and long-term uncertainties in the market place on the value of the utility's future resources.

TESTIMONY

Before the Alberta Utilities Commission, Proceeding #23757, Oral Testimony on behalf of the Alberta Electric System Operator re: Alberta Electric System Operator Application for Approval of the First Set of ISO Rules to Establish and Operate the Capacity Market, April 30 to May 3, 2019.

Before the Alberta Utilities Commission, Proceeding #23757, *Demand Curve and Energy and Ancillary Services Offset: Response to Intervener Evidence in Alberta Utilities Commission Proceeding #23757*, prepared by Kathleen Spees, J. Michael Hagerty, Cathy Wang, and Matthew Witkin, April 11, 2019, Appendix "A" to *Rebuttal Evidence of the Alberta Electric System Operator*, April 12, 2019.

Before the Federal Energy Regulatory Commission, Docket No. ER19-105-000, *Answering Affidavit of Samuel A. Newell, John M. Hagerty, and Sang H. Gang on behalf of PJM Interconnection, L.L.C, regarding Cost of New Entry Parameters*, December 14, 2018, Attachment B to *Answer of PJM Interconnection, L.L.C. to Protests and Comments*, December 17, 2018.

Before the Federal Energy Regulatory Commission, Docket No. ER19-105-000, *Affidavit of Samuel A. Newell, John M. Hagerty, and Sang H. Gang on behalf of PJM Interconnection,* *L.L.C*, October 11, 2018, Attachment E to *Re: PJM Interconnection, L.L.C., Docket No. ER19-105-000 Periodic Review of Variable Resource Requirement Curve Shape and Key Parameters*, October 12, 2018.

PUBLICATIONS

- "Reaching Climate Goals via Electrification Requires Foot on the Accelerator," (with Jurgen Wess), published by Public Utilities Fortnightly, February 2020.
- "A New Paradigm for Utilities: Electrification of the Transportation and Heating Sectors," (with Ryan Hledik, Ahmad Faruqui, Jürgen Weiss, Michael Hagerty, and Long Lam), published by the American Bar Association, November 2019.
- "Achieving 80% GHG Reduction in New England by 2050: Why the Region Needs to Keep its Foot on the Clean Energy Accelerator," (with Jurgen Weiss, Maria Castaner, and John Higham), prepared for the Coalition for Community Solar Access, September 2019.
- "The Total Value Test: A Framework for Evaluating the Cost-Effectiveness of Efficient Electrification," (with Ryan Hledik, Ahmad Faruqui, and John Higham), prepared with the Electric Power Research Institute, August 2019.
- "Cost Savings Offered by Competition in Electric Transmission: Experience to Date and the Potential for Additional Customer Value," (with Judy Chang, Hannes Pfeifenberger, Akarsh Sheilendranath, Simon Levin, and Wren Jiang), prepared for LSP Transmission Holdings, LLC, April 2019.
- "The Coming Electrification of the North American Economy: Why We Need a Robust Transmission Grid," (with Jurgen Weiss and Maria Castaner), prepared for WIRES Group, March 2019.
- "AESO Cost of New Entry Analysis: Combustion Turbines and Combined-Cycle Plants with November 1, 2021 Online Date," (with Johannes Pfeifenberger, Kathleen Spees, Mike Tolleth, Martha Caulkins, Emily Shorin, Sang Gang, Patrick Daou, and John Wroble), prepared for Alberta Electric System Operator, September 2018.
- "PJM Cost of New Entry: Combustion Turbines and Combined-Cycle Plants with June 1, 2022 Online Date," (with Samuel Newell, Johannes Pfeifenberger, Bin Zhou, Emily Shorin, Perry Fitz, Sang Gang, Patrick Daou, and John Wroble), prepared for PJM Interconnection, April 2018.
- "Fourth Review of PJM's Variable Resource Requirement Curve," (with Samuel Newell, David Luke Oates, Johannes Pfeifenberger, Kathleen Spees, John Imon Pedtke, Matthew Witkin, and Emily Shorin), prepared for PJM Interconnection, April 2018.

- "The Future of Cap-and-Trade Program in California: Will Low GHG Prices Last Forever?," (with Yingxia Yang, Ashley Palmarozzo, Hannah Sheffield, Metin Celebi, Marc Chupka, and Frank C. Graves), December 2017.
- "Modelling Enhancements for CAISO Transmission Planning: The Feasibilty and Value of Incorporating Scheduling Constraints into CAISO's Planning Model," (with Judy Change, Johannes Pfeifenberger, Kai Van Horn, John Imon Pedtke, and Jesse Cohen), prepared for LS Power, October 2017.
- "Blending In: The Role of Renewable Fuel in Achieving Energy Policy Goals," (with Marc Chupka and Philip Verleger Jr.), prepared for Growth Energy, August 2017.
- "Electrification: Emerging Opportunities for Utility Growth," (with Jurgen Weiss, Ryan Hledik, and Will Gorman), January 2017.
- "Valuation of Electric Power System Services and Technologies," (with M. Kintner-Meyer, J. Homer, P. Balducci, M. Weimar, Ira Shavel, Nicholas Powers, Yingxia Yang and Roger Lueken), prepared for U.S. Department of Energy, August 2016.
- "Peeking Over the Blendwall: An Analysis of the Proposed 2017 Renewable Volume Obligations," (with Marc Chupka, Nicholas Power, and Sarah Germain), prepared for Growth Energy, July 2016.
- "Clean Energy Resource Options for Massachusetts to Meet GHG Reduction Goals under the Global Warming Solutions Act (GWSA): A Synthesis of Relevant Studies," (with Judy Chang and Will Gorman), prepared for the Barr Foundation, June 2016.
- "Benefits of the Southwest Intertie Project-North," (with Johannes Pfeifenberger, Judy Chang, Pablo Ruiz and Cady Wiltsie), prepared for Great Basin Transmission, LLC, March 2016.
- "Issue Brief - The Clean Power Plan: Focus on Implementation and Compliance," (with Marc Chupka, Metin Celebi, Judy Chang, Ira Shavel, Kathleen Spees, Jurgen Weiss, Pearl Donohoo-Vallett and Michael Kline), January 2016.
- "Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades," (with Sam Newell, Bruce Tsuchida, Akarsh Sheilendranath, Nicole Irwin and Lauren Regan), prepared for NYISO and New York Department of Public Service Staff, September 2015.
- "Lake Erie Connector Market Assessment Report," (with Judy Chang, Johannes Pfiefenberger and Akarsh Sheilendranath), prepared for ITC Lake Erie Connector LLC, May 2015.

- "Electricity Baseline Report for the U.S. Power System," (with Ira Shavel, Nicholas Powers and Yingxia Yang), for Pacific Northwest National Laboratory and U.S. Department of Energy, April 2015.
- "EPA's Clean Power Plan and Reliability: Assessing NERC's Initial Reliability Review," (with Jurgen Weiss, Toshiki Bruce Tsuchida, and Will Gorman), prepared for the Advanced Energy Economy Institute, February, 2015.
- "Nebraska Renewable Energy Exports: Challenges and Opportunities," (with Judy Chang and Johannes Pfeifenberger), prepared for the Nebraska Power Review Board, December 12, 2014.
- "Stakeholder-Driven Scenario Development for the ERCOT 2014 Long-Term System Assessment," (with Judy Chang and Johannes Pfeifenberger), prepared for The Electric Reliability Council of Texas (ERCOT), September 30, 2014.
- "Policy Brief - EPA's Proposed Clean Power Plan: Implications for States and the Electric Industry," (with Metin Celebi, Kathleen Spees, Samuel A. Newell, Dean M. Murphy, Marc Chupka, Jürgen Weiss, Judy Chang, and Ira H. Shavel), June 2014.
- "Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM," report prepared for PJM Interconnection, LLC (with S. Newell, K. Spees, J. Pefiefenberger, Q. Liao, and with C. Ungate and J. Wroble at Sargent & Lundy), May 15, 2014.
- "2013 Offer Review Trigger Prices Study," (with Sam Newell and Quincy Lao), October 2013.
- "Recommendations for Enhancing ERCOT's Long-Term Transmission Planning Process," (with Judy Chang, Johannes Pfeifenberger, Samuel A. Newell, and Toshiki (Bruce) Tsuchida), prepared for The Electric Reliability Council of Texas (ERCOT), October 2013.
- "The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments," (with Judy Chang and Johannes Pfeifenberger), prepared for the Working Group for Investment in Reliable and Economic Electric Systems (WIRES), July 2013.
- "Managing Large-Scale Penetration of Intermittent Renewables," (with MIT Energy Initiative), April 2012.

PRESENTATIONS

- "Achieving 80% GHG Reduction in New England by 2050: Why the region needs to keep its foot on the clean energy accelerator," NECA Renewable Energy Conference, March 2020.
- "Transmission in a Decarbonized and Electrified World," LSI Transmission and Clean Energy in the Northeast, March 2019.
- "The Role of Transmission in the Future Electric Power System," WIRES University Transmission 101, February 2019.
- "On the Path to Decarbonization: Can Electricity Markets Adapt to Meet Carbon Goals in the Western U.S.?," LSI Buying and Selling Electric Power in the West, January 2019.
- "Seeking a Landing Point: Transmission Needs for U.S. Offshore Wind Generation," AWEA Offshore WINDPOWER Conference, October 2018.
- "Battery Storage Development: Regulatory and Market Environments," Philadelphia Area Municipal Analyst Society, January 2018.
- "Long-Term Implications of Negative Prices for West Coast Electricity Markets," LSI Buying & Selling Electric Power in the West, January 2018.
- "Transmission Planning Strategies to Accommodate Renewables," EUCI Renewable Energy Grid Operations, September 2017.
- "Impacts of Oregon's Coal Phase-Out on Coal Plant Economics in the Western U.S.," LSI Oregon's Clean Electricity and Coal Transition Plan, July 2016.
- "Valuation of Electric Power System Services and Technologies," U.S. Department of Energy Technical Workshop on Electricity Valuation, May 2016.
- "EPA CPP Scenarios—What Texas Is Likely to Do, and the Impacts on ERCOT," ERCOT Market Summit 2016 Pre-Summit Briefing, February 2016.
- "The Clean Power Plan: Implications for the Western Interconnect," EUCI Optimizing Carbon Market Mechanisms in the Western Interconnect, January 2016.
- "Electric Sector Investments in a Lower Carbon World," Notre Dame Mendoza School of Business Climate Investing Conference: Transition to a Low Carbon World, September 2015.
- "Nebraska Renewable Energy Export (LB 1115) Study," Nebraska Power Review Board, December 2014.
- "Trends and Benefits of Transmission Investments: Identifying and Analyzing Value," Ecology & Environment, Inc. 2013 Electric Transmission Seminar at Eagle Nest, September 2013.

SANG H. GANG
Senior Principal Consultant & Project Manager
Sargent & Lundy Consulting

Education

- Electrical Engineering Graduate Work—University of Illinois at Urbana-Champaign—IL, USA—2006
- BS Electrical Engineering—University of Illinois at Urbana-Champaign—IL, USA—2003

Registrations

Professional Engineer (Illinois)

Proficiencies

- Power Project Development Support & Owner's Engineering Services
- Power Project Due Diligence & Lender's Advisory Services
- Utility Planning – Generation and Transmission
- Electricity Markets – Capacity, Energy, and Ancillary Services
- Offshore Wind Projects
- Utility-Scale Solar Photovoltaic Projects
- Battery Energy Storage System
- Grid Modernization / Smart Grid technologies
- Power Project Grid Interconnection
- Electrical System Analysis and Design

Responsibilities

As a Senior Principal Consultant and a Project Manager within Sargent & Lundy's Consulting Group, Mr. Gang is responsible for planning and managing a wide range of projects in the electric power industry. He provides support for project development, owner's engineering, technical due diligence, independent engineering, construction monitoring, condition assessment, and technical advisory services for coal, gas, nuclear, and renewable, grid modernization, and transmission projects throughout the world. He has significant expertise in the evaluation of technology, plant engineering and design, key project contracts, project economics, and performance records.

Mr. Gang is one of the Sargent & Lundy's subject matter specialists in battery energy storage, grid modernization, smart grid, and solar PV power technology. He has extensive experience with domestic and international utility-scale PV projects and a wide variety of PV technologies. His solar project expertise includes conceptual design, solar resource evaluation, energy yield assessment, probabilistic analysis, electrical design, reliability, O&M, project development, contracting strategy, and financial evaluation.

Sargent & Lundy Experience

Utility Planning

Confidential Clients

- 2019 | Supported a major electric utility in their development of battery energy storage pilot projects. Scope included review of potential project candidates, preparation of EPC technical specification, and review of EPC bids.
- 2019 | Supported a utility in their transmission planning by evaluating alternative generation and transmission solutions to mitigate areal overload conditions. Worked involved in detailed modeling and analysis using ISO grid model.
- 2018 | Performed engineering and economic evaluation of the client's electric power system with respect to a potential shutdown of a major generation asset. The engineering evaluation included reviews of the capital expenditure plans, fixed and variable O&M numbers, and various performance metrics such as availability, forced outages, and heat rates, which were all used as inputs to the economic model. The economic evaluation calculated breakdowns of various energy production costs such as market purchases/sales, fuel costs, variable O&M costs, and other fixed costs.

Arizona Electric Power Cooperative, Inc. (AEPCO) | 2019

Provided detailed capital cost, O&M cost, and performance estimates for different candidate resource types including simple cycle frame-type gas turbine, aeroderivative gas turbine, reciprocal internal combustion engine, and combined cycle gas turbine projects. Our deliverables were provided as input to the client's long-term resource planning.

Alberta Energy System Operator (AESO) | 2019

Provided technical and legal support to AESO related to its filing to the Alberta Utilities Commission on the design of the Alberta capacity market.

Lansing Board of Water and Light (BWL) | 2019

Supported the BWL Transmission and Distribution Engineering Department in development and completion of seven Asset Life Cycle Plan documents, which contain information regarding the characteristics, performance, condition, maintenance, modeling, and the proposed management plan.

Alberta Energy System Operator (AESO) | 2018

Worked with the Brattle Group to perform cost of new entry (CONE) study in preparation of AESO's inauguration of capacity market.

PJM Interconnection | 2017

Worked with the Brattle Group to perform cost of new entry (CONE) study for review of PJM's Variable Resource Requirement (VRR) curve, which is an administratively determined representation of a demand curve for capacity used in the PJM Reliability pricing Model auction.

Sikeston Board of Municipal Utilities | 2017

Performed an evaluation of the costs and benefits of the client's existing interconnection configuration and alternative interconnection options.

United States Realty | 2013

US Steel Keystone Industrial Port Complex (KIPC)

- Performed high-level condition assessment and valuation of the 30-MW KIPC electrical distribution system and developed cost optimization plan.

Gas and Coal Power

Venture Global LNG | 2019

Calcasieu Pass LNG Export Facility

- Supported Venture Global LNG in performing various power system modeling and studies of the off-grid electrical system for an LNG liquefaction facility in Louisiana.

Fadhili Plant Cogeneration Company | 2018

Fadhili Combined Heat and Power Project

- Performed off-line audit of the Plant Accounting Settlement System and Fuel Demand Model as required by the Power Purchase Agreement (PPA) with one offtaker and Steam and Water Purchase Agreement (SWPA) with the other offtaker.

Confidential Clients

- 2019 | Performed technical advisory services to support development of 800-MW combined cycle power plant and 345-kV transmission line project, including solicitation supports for onshore/offshore site investigations contractor, Power Island OEM, power plant EPC contractor, and substation & transmission EPC contractor.

- 2018 | Performed technical due diligence reviews of 2x300-MW coal plant in operation and 2x660-MW coal plant under construction, in support of potential asset acquisition.
- 2017 | Performed technical due diligence reviews of 16 coal and gas fired power plants in Canada, U.S., and Australia, in support of potential asset acquisition.
- 2017 | Performed technical due diligence reviews of Norte-III combined-cycle power project in Mexico, in support of potential asset acquisition.
- 2016 | Performed technical due-diligence review of four-unit, 2,400-MW coal-fired power plant in U.A.E. for potential lenders.
- 2015 | Provided Owner's Engineering support for Independent Power Project (IPP) developer's bid to the Comisión Federal de Electricidad (CFE) for Noreste, Topolobampo-II, and Topolobampo-III combined cycle power projects in Mexico.
- 2013 | Performed technical due-diligence review of a two-unit, 834-MW combined cycle power project in Israel for a potential lender.

Dynegy | 2016

Project Manager for Independent Engineering review of four gas-fired combined cycle projects in the U.S.

GNPower Mariveles Coal Plant, Ltd. Co.

Mariveles Coal Power Station

- 2016 | Project Manager for new relay setting development and existing relay setting reconstitution.
- 2016 | Project Manager for the LP turbine blade failure assessment.
- 2016 | Project Manager for technical feasibility evaluation of new Generator Circuit Breaker addition and associated modifications to the plant auxiliary electrical distribution system.

Sithe Global | 2015–2016

Mariveles Coal Power Station

- Reviewed major plant remediation program and performed independent engineering review of the two-unit, 300-MW coal-fired power plant in the Philippines for the major equity shareholder of the plant.

Shamal Az-Zour Al-Oula K.S.C. | 2016

Az-Zour North (AZN) Phase 1 Independent Water and Power Project

- Project Manager for on-line audit of the Plant Accounting Settlement System and Fuel Demand Model.

Mirfa International Power & Water Company | 2015–2016

Mirfa Independent Water and Power Project

- Project Manager for off-line audit of the Plant Accounting Settlement System, Fuel Demand Model, and Outage Mode Model.

Venture Global LNG | 2015–2016

Calcasieu Pass LNG Export Facility

- Supported Venture Global LNG as Owner's Engineer in technical feasibility studies such as the transient stability analysis of the off-grid electrical system for an LNG liquefaction facility in Louisiana.

Siddiqsons Energy | 2015

Performed feasibility study and prepared technical specifications for developing a 350 MW supercritical coal-fired power plant in Karachi, Pakistan.

SK Engineering & Construction (SK E&C) | 2014

Jangmoon Combined-Cycle Power Plant

- Provided technical advisory services to support SK E&C in the review of basic engineering of the two-unit, 2x2x1, 1,820-MW combined cycle power project in South Korea.

Korea Sothern Power Company (KOSPO) | 2014

Kelar Combined-Cycle Power Plant

- Supported KOSPO as Owner's Engineer in the engineering design review of the 2x2x1, 517-MW combined cycle power project in Chile.

Hyundai Heavy Industries (HHI) | 2013–2014

Jeddah South Thermal Power Plant Stage 1

- Provided technical advisory services to support HHI in the basic engineering, detailed engineering, and start-up and commissioning of the four-unit, 2,640-MW supercritical oil-fired thermal power project in Saudi Arabia.

Renewable Energy

Lincoln Clean Energy | 2019

Provided owner's engineering services to support conceptual layout design optimization, tracker technology selection, and EPC bid solicitation for the 400-MW 2W Permian Solar Project in Texas. Also provided owner's engineering services to support EPC bid solicitation for the 40-MW/40-MWh battery energy storage systems to be co-located with the Permian Solar Project.

Confidential Clients

- 2019 | Evaluated the impact of interconnecting the client's offshore wind project to the NYISO grid by performing System Reliability Impact Study.
- 2018 | Worked with NERA Economic Consulting to support a major offshore wind developer by performing competitor bid analyses for offshore wind auctions in New York and New Jersey. Sargent & Lundy's scope included evaluation of potential interconnection points and estimates of capital costs, O&M cost, and annual generation levels.
- 2018 | Owner's engineer for a new 100-MW solar PV project in Mexico. Supported EPC and O&M contract negotiations and preliminary site and technology evaluations.
- 2018 | Prepared CAISO interconnection applications and supplemental technical requirements for 100+ MW solar PV + battery energy storage projects.
- 2018 | Prepared MISO interconnection application and supplemental technical requirements for 100+ MW solar PV project.
- 2018 | Performed GIS-based site identification study for multiple small utility-scale solar PV projects throughout the state of Michigan.
- 2017 | Performed technical due diligence review of two 60-MW biomass projects in Georgia for potential asset acquisition.
- 2016 | Developed conceptual layout, preliminary electrical design, equipment selection, energy production, detailed capital cost estimates, and LCOE calculation for a 20-MW solar PV project being developed in conjunction with reciprocal engine project in central U.S.
- 2016 | Developed conceptual layout, energy production, capital cost estimates and expenditure schedule for 20-MW solar PV project being developed adjacent to existing coal-fired power plant in central U.S.
- 2016 | Performed market study and financial evaluation of adding a battery energy storage system to an existing wind project in the PJM region by assessing the new PJM capacity performance

market to evaluate the battery system economics.

- 2016 | Performed technical and financial feasibility study of adding a battery energy storage system to the existing metropolitan railway system in San Francisco.

Inter-American Development Bank | 2015

Performed technical due diligence of a 100-MW single-axis tracking solar PV project in northern Chile.

Electric Power Research Institute (EPRI)

- Developed utility-scale performance and financial models of various PV technologies to update the EPRI Report, “Solar Energy Technology Guide - 3002001638.” (2014 & 2015)
- Developed utility-scale performance models of various PV technologies to update the EPRI Report, “Engineering and Economic Evaluation of Central-Station Solar Photovoltaic Power Plant.” (2013)

TerraForm Power | 2015

Performed technical due diligence to support asset acquisition of two 10-MW solar PV projects in Ontario, Canada.

International Finance Corporation

San Carlos Solar PV Projects

- 2015 | Performed operations monitoring of the three projects
- 2014 | Performed independent solar resource and energy yield assessments and technical due-diligence reviews of three solar PV projects—22-MW, 18-MW, and 22-MW—in the Philippines.

Overseas Private Investment Corporation

- 2015 | Content Solar PV Project
    - Performed pre-construction technical due diligence of a 22-MW solar PV project in Jamaica.
- 2015 | Real El Salvador Solar PV Project
    - Performed independent energy yield assessments to support financing of a portfolio of eight solar PV projects in El Salvador.
- 2014 | Confidential Wind Project
    - Performed Independent Engineering review of wind resource and energy yield assessment for a 50-MW wind project in Pakistan.
- 2013 | Confidential Solar PV Project
    - Performed Independent Engineering reviews of the solar resource, project financial projections, contract reviews, PV technology, independent design reviews, market pricing review, and O&M approach of a 3-MW solar PV project in Tanzania.

Macquarie Capital | 2013

Simon Solar PV Project

- Performed lender's technical due diligence review of a 30-MW solar PV project in Georgia.

Standard Bank of South Africa

- 2013 | Beaufort West PV Project
  - Performed Independent Engineering review of projected energy yield model of a 60-MW solar PV project in South Africa.
- 2013 | MetroWind Project
  - Performed Independent Engineering review of construction progress of a 27-MW wind project in South Africa.

NextEra Energy Resources, LLC

- 2015 | Javelina Wind Project
  - Performed Independent Engineering balance-of-plant reviews of a 250-MW wind project in Texas.
- 2013 | Red River Portfolio
  - Performed Independent Engineering balance-of-plant reviews and compliance review of interconnection requirements of two commercially operating wind farms in Texas (255 MW total) to support re-financing.
- 2013 | Steele Flats Wind Projects
  - Performed Independent Engineering balance-of-plant reviews of a 75-MW wind project in Nebraska.

Nuclear Power

Korea Hydro & Nuclear Power (KHNP) | 2016–2019

Project Manager for classroom training program consisting of 20 different technical subject courses in nuclear power plant design and analysis. Each course was offered over 4–8-week durations in the Sargent & Lundy's Chicago office.

KEPCO International Nuclear Graduate School | 2018

Project Manager for one-week long classroom training program about Root Cause Analysis (RCA) and Probabilistic Risk Analysis (PRA).

Dynegy | 2017

Performed due-diligence review of the Comanche Peak Nuclear Power Plant, focusing on identifying any material or major issues associated with the plant and operations that could have a significant cost impact.

Hyundai Engineering Co. (HEC) | 2016

Project Manager for technical advisory services and training program in nuclear power plant steam generator replacement.

Emirates Nuclear Energy Corporation | 2014

Barakah Nuclear Power Plant Units 1 & 2

- Performed electrical review of selected safety-related plant systems against licensing basis as part of the Independent Design Review of Barakah Nuclear Plant Units 1 & 2 engineering design.

Tennessee Valley Authority (TVA), Browns Ferry Nuclear Plant

- 2009–2013 | Emergency Diesel Generator Governor Upgrade
- 2012–2013 | NFPA-805: EECW System Circuit Modification
- 2012 | NFPA-805: Emergency Diesel Generator Protective Relay Circuit Modification
- 2012 | LPCI MG Set Abandonment
- 2010–2011 | Service Building Transformer Replacement
- 2010–2012 | Generator Voltage Regulator Replacement
- 2008–2012 | Low Voltage Circuit Breakers Replacement
- 2008–2012 Emergency Diesel Generator Turbocharger Lube Oil System Modification

Testimony and Regulatory Filings

- Before the Alberta Utilities Commission, Proceeding No. 23757, Alberta Electric System Operator (AESO) Application for Approval of the First Set of ISO Rules to Establish and Operate the Capacity Market, Participated in the hearing as a member of the AESO's witness panel on May 1-3, 2019.
- Before the Federal Energy Regulatory Commission, Docket No. ER19-105-000, Answering affidavit of Samuel A. Newell, John M. Hagerty, and Sang H. Gang on behalf of PJM Interconnection, L.L.C. regarding Cost of New Entry Parameters, December 14, 2018.

Languages

- Korean (Fluent)

Exhibit No. 2

Gross Avoidable Cost Rates for Existing Generation and Net Cost of New Entry for New Energy Efficiency

PREPARED FOR

PJM

PREPARED BY

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J. Michael Hagerty
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March 17, 2020

THE Brattle GROUP

Notice

- This report was prepared for PJM Interconnection, L.L.C., in accordance with The Brattle Group's engagement terms, and is intended to be read and used as a whole and not in parts.
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Table of Contents

Executive Summary

In December 2019, the Federal Energy Regulatory Commission (FERC) ordered PJM Interconnection, L.L.C. (PJM) to expand the application of its Minimum Offer Price Review (MOPR) in its forward capacity market. To help implement this order, PJM retained The Brattle Group (Brattle) and Sargent & Lundy (S&L) to analyze the gross avoidable costs rates (ACRs) for several types of existing generation and the net cost of new entry (Net CONE) for new energy efficiency (EE) in the 2022/2023 Base Residual Auction. PJM will use the values to inform default offer floor prices for each resource type in its auctions.

Existing generation resources vary considerably in their characteristics and costs, even for a given type of resource. To inform PJM's determination of a single ACR for each resource type, we present a range of costs for the fleet of resources of each type operating in the PJM market. PJM can then determine the default offer floor price for each resource type at a value within the range that best fits its approach to complying with the order, trading off the risks of under-mitigation against the risks of over-mitigation and/or a burdensome amount of unit-specific reviews.

To do so, we reviewed the range of characteristics of resources installed in the PJM market and identified the primary cost drivers among those characteristics for each resource type. We then identified for each resource type the characteristics of a "representative plant" that is widely representative of most of the fleet as well as characteristics for "representative low-cost" and "representative high-cost" plants to inform the range of costs for each type of existing generation resource.

Given the assumed characteristics, we then estimated the costs of the representative plants to inform the Gross ACRs and the variable O&M costs for use in PJM's net energy and ancillary services (E&AS) revenue analysis. These cost estimates reflect PJM's market rules concerning the scope of costs that are includable in the Gross ACRs versus those that can be included in cost-based energy offers (and thus accounted for in the net E&AS revenue component of Net ACRs). Following guidance provided by PJM, the costs of major maintenance and overhauls on systems directly related to the production of electricity are included in variable costs as a "maintenance adder."

Table 1 below shows the resulting cost estimates for each existing generation resource type on a per-megawatt (MW) of nameplate capacity basis for informing PJM's 2022/2023 Gross ACRs.

Table 1: Existing Generation Costs for 2022/2023 Gross Avoidable Cost Rates
(in nominal dollars per MW-day)

Resource Type	Representative Low-Cost Plant	Representative Plant	Representative High-Cost Plant
Single-Unit Nuclear	---	**$697**	---
Multi-Unit Nuclear	$405	**$445**	$457
Coal	$74	**$80**	$166
Gas CC	$55	**$56**	$79
Gas CT	$42	**$50**	$65
Onshore Wind	$76	**$83**	$128
Solar PV	$29	**$40**	$60
Diesel Generator	---	**$3**	---

Table 2 below shows our estimates of the variable costs for each resource type that are consistent with the Gross ACR estimates. The variable costs shown include non-fuel operating costs and maintenance adders for all resource types.

Table 2: Existing Generation Costs for 2022/2023 Variable Costs
(in nominal dollars per MWh)

Resource Type	Representative Low-Cost Plant	Representative Plant	Representative High-Cost Plant
Single-Unit Nuclear	---	$4.00	---
Multi-Unit Nuclear	$2.63	$2.67	$3.66
Coal	$9.17	$9.56	$9.20
Gas CC	$2.24	$2.57	$2.53
Gas CT	$7.54	$7.54	$4.98
Onshore Wind	$0.00	$0.00	$0.00
Solar PV	$0.00	$0.00	$0.00
Diesel Generator	---	$0.00	---

Note: The estimated variable costs are calculated based on an assumed capacity factor for each resource type. We provide details on the assumed capacity factors and how to adjust the variable costs for different capacity factors in the report below.

To calculate the Net CONE for new EE resources, we analyzed the total costs and benefits of EE programs. Net CONE represents the amount of capacity market revenues that a resource would need to justify the investment. It represents the gap between the total costs of the EE investments (including all utility program costs and participant's out-of-pocket costs) and other revenues or benefits of EE (reduced wholesale energy costs and transmission and distribution system costs) that would need to be filled by revenues from the capacity market.

We reviewed publicly-available reports on EE program cost effectiveness and identified sufficient costs and performance data to calculate Net CONE for EE programs of three representative PJM utilities with the largest EE portfolios in their respective states: Baltimore Gas and Electric, Pennsylvania Power and Light and Commonwealth Edison. For those utilities, we identified 30 programs whose capacity could qualify for PJM's capacity market. We then calculated the Net CONE for each EE program by analyzing its costs, characteristics, and benefits per MW of qualified capacity. Finally, we calculated the capacity-weighted average across all qualified programs to produce a single Net CONE value for EE.

Table 3 below shows the estimated Net CONE for new EE in the 2022/2023 BRA is $64/MW ICAP-day, or $58/MW UCAP-day (in nominal dollars).

Table 3: 2022/2023 Net Cost of New Entry for New Energy Efficiency
(in nominal dollars)

Gross CONE	***$/kW ICAP-yr***	**$235**
Energy Savings	*$/kW ICAP-yr*	$177
T&D Savings	*$/kW ICAP-yr*	$35
Net CONE	***$/kW ICAP-yr***	**$23**
Net CONE	***$/MW ICAP-day***	**$64**
Net CONE	***$/MW UCAP-day***	**$58**

I. Introduction

In December 2019, the Federal Energy Regulatory Commission (FERC) issued an order in Docket Nos. EL 16-49-000 and EL 18-178-000 related to PJM Interconnection's (PJM) forward capacity market that directed PJM to expand its application of the current Minimum Offer Price Rule (MOPR) to "address state-subsidized electric generation resources."[1] FERC directed PJM to submit a compliance filing consistent with the order within 90 days.[2]

To implement the order, PJM requested that consultants at The Brattle Group and Sargent & Lundy (S&L) analyze:

- Gross avoidable costs rates (ACRs) for existing generation, and
- Net cost of new entry (Net CONE) for new energy efficiency (EE).

PJM will then estimate the energy and ancillary services (E&AS) net revenues for the existing generation resources and calculate Net ACRs for each resource type and zone. PJM will set default offer price floors for existing generation resources in its forward capacity market at the Net ACRs for each resource type and for new EE at its Net CONE. Resources will be able to receive a Unit-Specific Exemption to offer below the default offer price floor if they can justify their offer during a review of their expected costs and revenues by the Independent Market Monitor (IMM).

II. Gross ACRs for Existing Generation

A. Scope of Analysis

PJM requested that we estimate Gross ACRs for the following existing generation resource types:

- Single-unit nuclear plants
- Multi-unit nuclear plants
- Coal plants

1 U.S. Federal Energy Regulatory Commission, "FERC Directs PJM to Expand Minimum Offer Price Rule", News Release, December 19, 2019. Available at: https://www.ferc.gov/media/news-releases/2019/2019-4/12-19-19-E-1.asp#.Xl04BahKiHs

2 169 F.E.R.C. ¶ 61,239 (December 19, 2019).

- Natural gas-fired combined-cycle plants (CC)
- Natural gas-fired combustion turbine plants (CT)
- Onshore wind plants
- Large-scale (>1 MW) solar photovoltaic plants
- Behind-the-meter diesel generator plants

Gross ACRs reflect the fixed costs of operating an existing generation resource for an additional year, while the variable costs of operating a resource are accounted for in net E&AS revenues, then combined to calculate Net ACRs. The combination should include all avoidable costs to operate the resource for another year. Costs that are incurred infrequently to extend the life of the resource or enhance its performance for more than a year are not to be included in the Gross ACR or variable costs.

To determine which costs to include in the Gross ACR and which to include in variable costs, PJM staff reviewed the specifications in their tariff and operating agreements, and provided guidelines to follow based on their interpretation. The PJM Open Access Transmission Tariff (OATT) Attachment DD section 6.8(c) specifies that "[v]ariable costs that are directly attributable to the production of energy shall be excluded from a Market Seller's generation resource Avoidable Cost Rate."[3] Section 6.8 also lists eleven components of Avoidable Cost Rates. The PJM Operating Agreement Schedule 2 further specifies the expenses allowed to be included in the maintenance adder as a variable cost as part of energy offers, rather than in the Gross ACR: "Allowable expenses include repair, replacement, and major inspection, and overhaul expenses including variable long term service agreement expenses."[4] Schedule 2 also states that "preventative maintenance and routine maintenance on auxiliary equipment like buildings, HVAC, compressed air, closed cooling water, heat tracing/freeze protection, and water treatment" cannot be included in cost-based energy offers, and thus are included in the Gross ACR.[5] We understand that PJM interprets this to mean that all maintenance costs for systems directly related to electric production can be included in the operating costs maintenance adder for cost-based energy offers, and thus are excluded from the Avoidable Cost Rates.[6]

Given that guidance, we identify the types of maintenance costs included in the Gross ACR and those included in the variable cost maintenance adder, and estimate the costs of each accordingly, as reported below. Our approach aligns with the categories identified in Section 6.8 of the OATT

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3 PJM, PJM Open Access Transmission Tariff, Attachment DD Market Power Mitigation, Section 6.8(c), accessed March 9, 2020, https://pjm.com/directory/merged-tariffs/oatt.pdf, p. 3429.

4 PJM, PJM Operating Agreement, Operating Agreement Schedule 2, Section 1.1(e), accessed March 9, 2020, https://www.pjm.com/directory/merged-tariffs/oa.pdf, p. 468.

5 PJM, PJM Operating Agreement, Operating Agreement Schedule 2, Section 1.1(e), accessed March 9, 2020, https://www.pjm.com/directory/merged-tariffs/oa.pdf, p. 468.

6 Based on discussions with PJM, the systems "directly attributable to electric production" include steam turbine, gas turbine, generator, boiler, Heat Recovery Steam Generators (HSRG), main steam, feed water, condensate, condenser, cooling towers, transformers, controls, and fuel systems.

as inputs to the ACRs, but based on PJM's guidance we do not include the Capacity Performance Quantifiable Risk (CPQR) premium nor the investment described as a part of Avoidable Project Investment Recovery Rate (APIR) for the purposes of setting the default offer floor prices.

B. Analytical Approach

There is significant variability in the costs of existing generation resources of a given type in PJM due to several factors, including: (1) the technologies used and how those changed over time; (2) the configuration of the units, including pollution controls; (3) the unit size; (4) the unit age; (5) how the resource has been operated; and (6) the level of maintenance performed in previous years on the plants. Considering this variability, we developed an approach to inform PJM of the range of costs for each type of existing generation resources so they can determine where on the range of costs best fits their approach to setting the default offer floor prices in the capacity market.

To do so, we reviewed the range of characteristics of resources that are installed in the PJM market and identified the primary cost drivers among those characteristics for each resource type.

We then identified for each resource type the characteristics of a "representative plant" that is widely representative of the costs of most of the fleet. In addition, we developed characteristics for a "representative low-cost plant" and a "representative high-cost plant" to inform the likely range of costs for each type of existing resources in PJM. These representative plants do not reflect the very highest and lowest cost plants in the market, but instead represent a population of plants near the high and low ends of the range.

Given the assumed characteristics, we then estimated the costs of the representative plants to inform the Gross ACRs and the variable O&M costs for use in PJM's net E&AS analysis. Our cost estimates are primarily based on our analysis of publicly-reported costs for plants with characteristics similar to the representative plants for each resource type, which we validated against confidential cost estimates within S&L's project database.

Our analysis incorporates input from the IMM and stakeholders. We shared preliminary results with the Internal Market Monitor on February 26, and with PJM stakeholders during a Markets Implementation Committee meeting on February 28 and received feedback from stakeholders on our approach and results. We reviewed the feedback provided during these meetings and incorporated it into our analysis where applicable.

C. Existing Generation Cost Estimates

1. Single-Unit Nuclear Plants

There are currently only three single-unit nuclear plants in the PJM market, as shown in Figure 1 below: the 970 MW Davis Besse plant and 1,310 MW Perry plant in Ohio and the 1,290 MW Hope Creek plant in New Jersey. Due to the small number of plants and the limited variation among them, we specified a single representative plant: a 35-year-old 1,200 MW Boiling Water Reactor BWR) unit in Ohio.

As noted above, we relied on costs reported in the 2019 NEI "Nuclear Costs in Context" report to develop cost estimates for both the single-unit and multi-unit nuclear plants.[7] The NEI report is the most comprehensive source of cost data that is publicly available for both merchant and regulated nuclear power plants. In this report, NEI provides the average costs incurred in 2018 across all nuclear units in the U.S. on a per-MWh basis, as well as the average costs for several sub-categories of nuclear plants: single-unit versus multi-unit plants; one-plant operators versus multiple-plant operators; plants competing in wholesale markets versus those under regulated cost-of-service; and boiling water reactor versus pressurized water reactor (PWR) plants. The costs are decomposed into three cost components: fuel costs, operating costs, and capital costs. For operating costs and capital costs, NEI further identifies several sub-categories of costs and shows the total 2018 costs for each in a series of bar charts.

We reviewed the NEI data to identify which costs are most applicable to the representative plants in PJM, and which costs components should be included in the Gross ACR as opposed to the variable costs based on PJM's market rules.

- **Capital Costs**: We estimated annual avoidable capital costs of $1.91/MWh as part of Gross ACR and $3.45/MWh as variable costs based on the following decomposition of NEI's capital costs for single-unit plants.[8] We started with the average capital costs for single-unit plants of $8.34/MWh.[9] We determined that the Enhancements and Capital Spares components of the capital costs (36% of total 2018 capital costs based on a detailed cost breakdown provided by NEI) should not be included in either Gross ACRs or variable costs since they reflect costs that extend the life of the plant beyond a year and would not be expected to be incurred on an annual basis. We assumed that the Sustaining costs (41% of total 2018 capital costs) reflect investment in systems directly related to electric production that are necessary to maintain plant performance, and thus by PJM's market rules should be included in variable costs. The remaining 23% of the total 2018 capital costs include upgrades to the plant that are expected to occur on an annual basis and are not directly related to electricity production so are included in the Gross ACR.

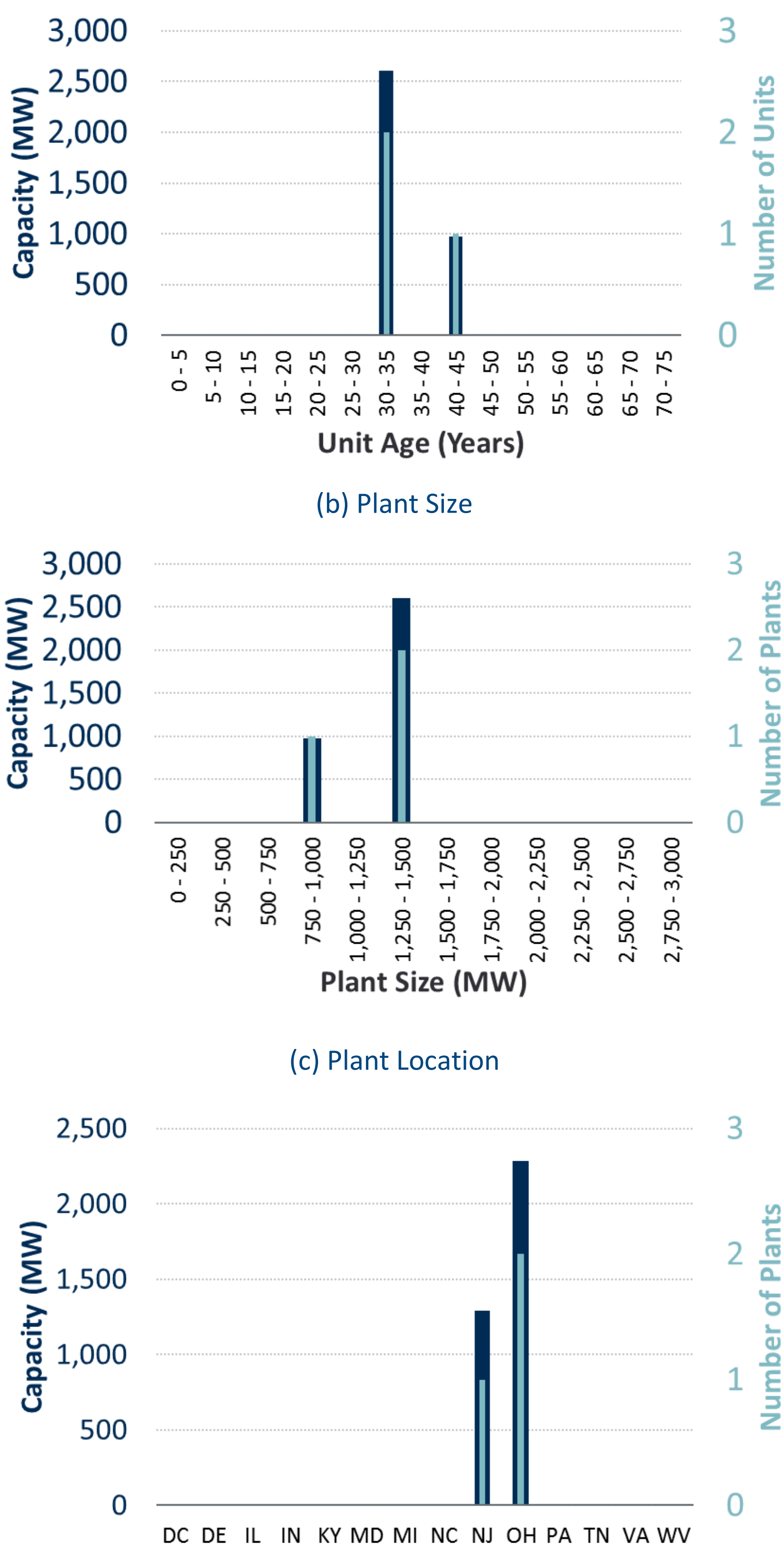
7 Nuclear Energy Institute, Nuclear Costs in Context, September 2019. ("NEI Report') Available at: https://www.nei.org/CorporateSite/media/filefolder/resources/reports-and-briefs/nuclear-costs-in-context-201909.pdf

8 NEI Report, p. 4.

9 NEI Report, p. 2.

Figure 1: Single-Unit Nuclear Fleet Characterization

(a) Unit Age



Source: ABB, Energy Velocity Suite, accessed January 15, 2020.

- **Non-Fuel Operating Costs:** We estimated that the avoidable fixed operating costs is \$28.80/MWh and the variable operating costs are \$0.54/MWh for a single-unit BWR nuclear plant. We started with the operating costs for the average single-unit plant in the U.S. of \$27.82/MWh.[10] We then increased the average costs by 5% (\$1.52/MWh) to \$29.34/MWh, based on the relative operating costs of BWR plants and PWR reported by NEI.[11] The components of operating costs primarily reflect labor costs that are not directly attractable to the production of electricity and so are included in the Gross ACR.[12] We interpret the Materials & Services costs (1.9% of total 2018 operating costs) to account for consumables required to operate the nuclear plants and thus include those costs as variable operating costs. The remaining 98% of the total 2018 operating costs are included in the Gross ACR. We applied these percentages to the total operating costs for a single-unit BWR plant (\$29.34/MWh) to calculate the variable and fixed operating costs.

The data reported by NEI reflect the costs for operating nuclear plants in 2018. To estimate costs in 2022-2023 we reviewed the trends for each cost component. Operating costs (the largest cost component) are expected to remain relatively flat, while capital costs are declining slightly and may fall further on a nominal basis due to a reduction in regulatory capital expenditures.[13] The EIA projects that nuclear fuel costs are expected to increase by 0.2% above inflation through 2050.[14] Based on these trends, we concluded that the total costs of operating a nuclear plant are likely to remain constant in nominal terms from 2018 to 2022. For simplicity, we assume that each of the three components also stay constant in nominal terms even though there is evidence that fuel costs may slightly increase and capital costs may decrease.

Property taxes are not included in the NEI cost data. To estimate the property taxes paid by nuclear power plants to be included in the Gross ACR, we researched public records related to nuclear power plants in PJM and identified property taxes paid by six plants. Based on those records, we estimate that the average property taxes for nuclear plants in PJM are \$0.77/MWh, or \$17/MW-day.[15] These costs can be considered avoidable even if they continue when the plant retires since they would then no longer be paid by the plant owner, but by the plant's decommissioning fund.

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10 NEI Report, p. 2.

11 The average operating costs for all BWR plants (both single-unit and multi-unit plants) is \$21.10/MWh, which is higher than the average operating costs of a PWR of \$18.97/MWh. Based on these values, we estimated that the costs of BWR plant are 5% higher cost than the average plant regardless of technology. NEI Report, p. 3.

12 NEI Report, p. 5.

13 NEI Report, pp. 4-5.

14 EIA, Annual Energy Outlook 2020, Table 3. Energy Prices by Sector and Source, January 29, 2020.

15 We identified publicly available information on property taxes for 8 nuclear plants in PJM. The property taxes had been paid between 2014 and 2020 and we assumed that they remain constant in nominal dollars. The reported property taxes or "taxes paid to the local government" ranged from \$1/MW-day to \$60/MW-day.

Finally, we assumed that nuclear plants in PJM will generate electricity with a capacity factor equal to the national average of 92.3% in 2018, which we use to convert the total costs reported on a per-MWh basis to per-MW-day for use as Gross ACR values.[16]

As shown in Table 4 below, we estimate that the Gross ACR for a single-unit nuclear plant in PJM is $697/MW-day (in 2022 dollars). We estimate that the variable costs are $4.00/MWh (in 2022 dollars), including $0.54/MWh for operating costs and $3.45/MWh for the maintenance adder.

Table 4: Estimated 2022 Costs for Existing Single-Unit Nuclear Plants in PJM
(in nominal dollars)

	Units	Single-Unit Nuclear Plant
Capacity	*Nameplate MW*	1,200
Gross ACR		
Fixed Operating Costs	*$/MWh*	$28.80
Fixed Capital Costs	*$/MWh*	$1.91
Property Taxes	*$/MWh*	$0.77
Total	*$/MWh*	$31.47
Gross ACR	***$/MW-day***	**$697**
Variable Costs		
Variable Operating Costs	*$/MWh*	$0.54
Maintenance Adder	*$/MWh*	$3.45
Total Variable Costs	***$/MWh***	**$4.00**

Note: We estimated the maintenance adder assuming a 92.3% capacity factor. If a different capacity factor will be assumed by PJM, the maintenance adder should be adjusted based on the ratio of 92.3% to the assumed capacity factor.

We recommend that PJM assume the fuel costs for single-unit nuclear plants are $5.05/MWh (in 2022 dollars) in its analysis of the net E&AS revenues, based on the average fuel costs for nuclear plants in wholesale markets reported by NEI.[17]

2. Multi-Unit Nuclear Plants

Most nuclear plants in the PJM market have multiple units installed at the same site. In total, there are currently 14 multi-unit nuclear plants operating in the PJM market. The age, size, and locations of these plants as shown in Figure 2 below. The capacity of multi-unit nuclear plants in PJM are

16 NEI, U.S. Nuclear Industry Capacity Factors, https://www.nei.org/resources/statistics/us-nuclear-industry-capacity-factors, March 2019.

17 NEI Report, p. 3.

mostly in the range of 2,000 – 2,750 MW, and in most cases these plants are 30 – 50 years old. There are six states in PJM with nuclear plants, with the most located in Pennsylvania and Illinois.

Based on our experience estimating costs for nuclear plants, the most significant cost drivers for nuclear plants are the technology (BWR versus PWR), locational labor costs and property taxes, and investments necessary to meet regulatory requirements for continuing to operate.

For the multi-unit nuclear plants, we set the characteristics of a representative plant to be a 40-year-old 2,400 MW (two 1,200 MW units) BWR plant in Pennsylvania with minimal regulatory costs. For the representative low-cost plant, we modified the technology to a PWR plant due to its lower cost of operations. For the representative high-cost plant, we assume a plant similar to the representative plant will incur additional ongoing regulatory costs to maintain operations.

We include the same scope of costs for the Gross ACR and variable costs as explained above for the single-unit nuclear plants, and the following cost for each category included in the NEI report:

- **Capital Costs**: We estimate annual avoidable capital costs of $1.28/MWh as part of Gross ACR and $2.33/MWh as variable costs for the representative plant. Similar to the approach for the single-unit plant, we started with the average capital costs for multi-unit nuclear plants of $5.62/MWh.[18] We apply the same assumptions for the composition of the capital costs as described above for single-unit plants, with 23% of the capital costs included in the Gross ACR, 41% included in variable costs, and 36% excluded from Gross ACR and variable costs since they reflect costs that extend the life of the plant beyond a year. For the representative high-cost plant, we increase the total capital costs to the average costs for regulated nuclear plants of $8.02/MWh to reflect higher ongoing regulatory costs.[19]
- **Operating Costs:** We estimate that the avoidable fixed operating costs for a multi-unit nuclear plant are $18.05/MWh and the variable operating costs are $0.34/MWh. This is based on the operating costs for the average multi-unit plant in the U.S. of $17.44/MWh, adjusted upward by $0.95/MWh to $18.39/MWh to account for the higher costs of a BWR plant.[20] We assume that 98% of the costs are included in the Gross ACR and 2% in variable costs. For the representative low-cost plant, we reduce the operating costs for the multi-unit nuclear plant by $1.86/MWh to reflect the lower costs of operating a PWR plant based on the lower operating costs of PWR plants reported by NEI for each type of reactor design.[21]

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18 NEI Report, p. 2.

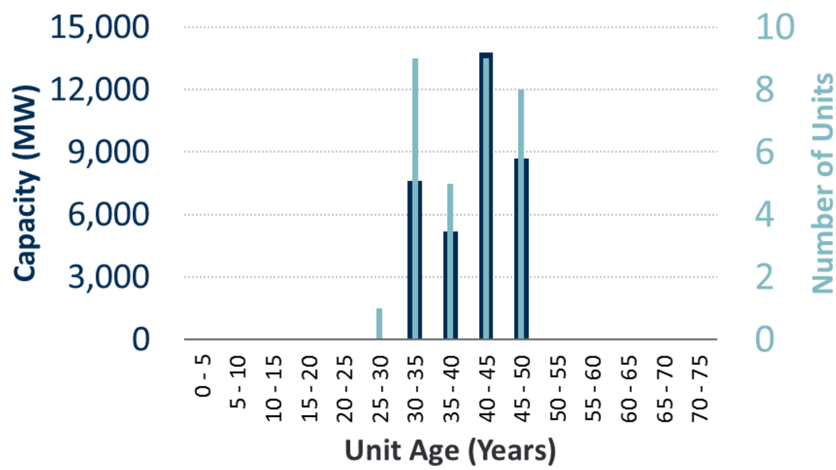
19 NEI Report, p. 3.

20 NEI Report, p. 2.

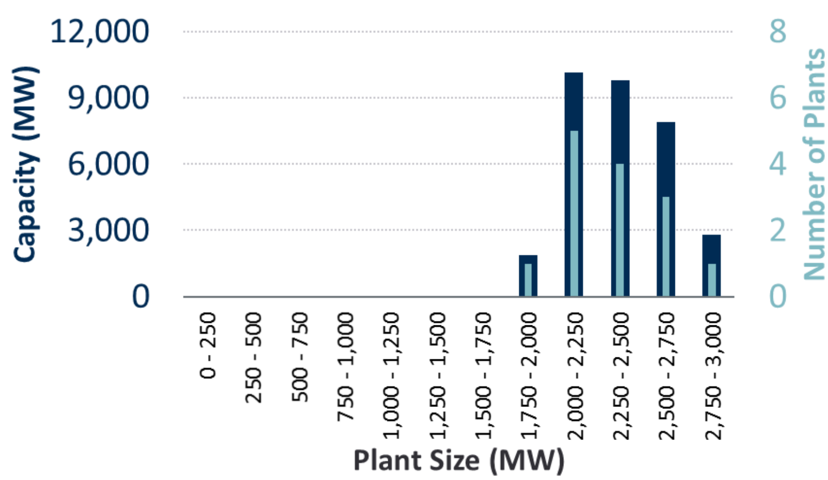
21 NEI Report, p. 3.

Figure 2: Multi-Unit Nuclear Fleet Characterization

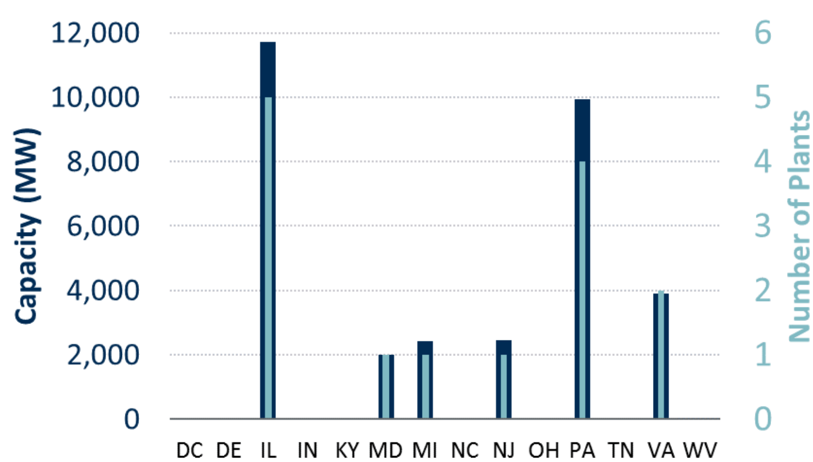
(a) Unit Age



(b) Plant Size



(c) Plant Location



Source: ABB, Energy Velocity Suite, accessed January 15, 2020.

As shown in Table 5 below, we estimate the Gross ACR for a representative multi-unit nuclear plant in PJM to be $445/MW-day, with a range of $405/MW-day to $457/MW-day (in 2022 dollars). The estimated variable costs for a multi-unit nuclear plant is $2.67/MWh with a range of $2.63/MWh to $3.66/MWh (in 2022 dollars).

Table 5: Estimated 2022 Costs for Existing Multi-Unit Nuclear Plants
(in nominal dollars)

		Multi-Unit Nuclear Plant		
	Units	**Representative Low-Cost Plant**	**Representative Plant**	**Representative High-Cost Plant**
Capacity	*Nameplate MW*	2,400	2,400	2,400
Gross ACR				
Fixed Operating Costs	*$/MWh*	$16.23	$18.05	$18.05
Fixed Capital Costs	*$/MWh*	$1.28	$1.28	$1.83
Property Taxes	*$/MWh*	$0.77	$0.77	$0.77
Total	*$/MWh*	$18.28	$20.10	$20.65
Gross ACR	***$/MW-day***	**$405**	**$445**	**$457**
Variable Costs				
Variable Operating Costs	*$/MWh*	$0.31	$0.34	$0.34
Maintenance Adder	*$/MWh*	$2.33	$2.33	$3.32
Total Variable Costs	***$/MWh***	**$2.63**	**$2.67**	**$3.66**

Note: We estimated the maintenance adder assuming a 92.3% capacity factor. If a different capacity factor will be assumed by PJM, the maintenance adder should be adjusted based on the ratio of 92.3% to the assumed capacity factor.

Similar to single-unit plants, we recommend that PJM assume the fuel costs for multi-unit nuclear plants are $5.05/MWh (in 2022 dollars) in its analysis of the net E&AS revenues.

3. Coal Plants

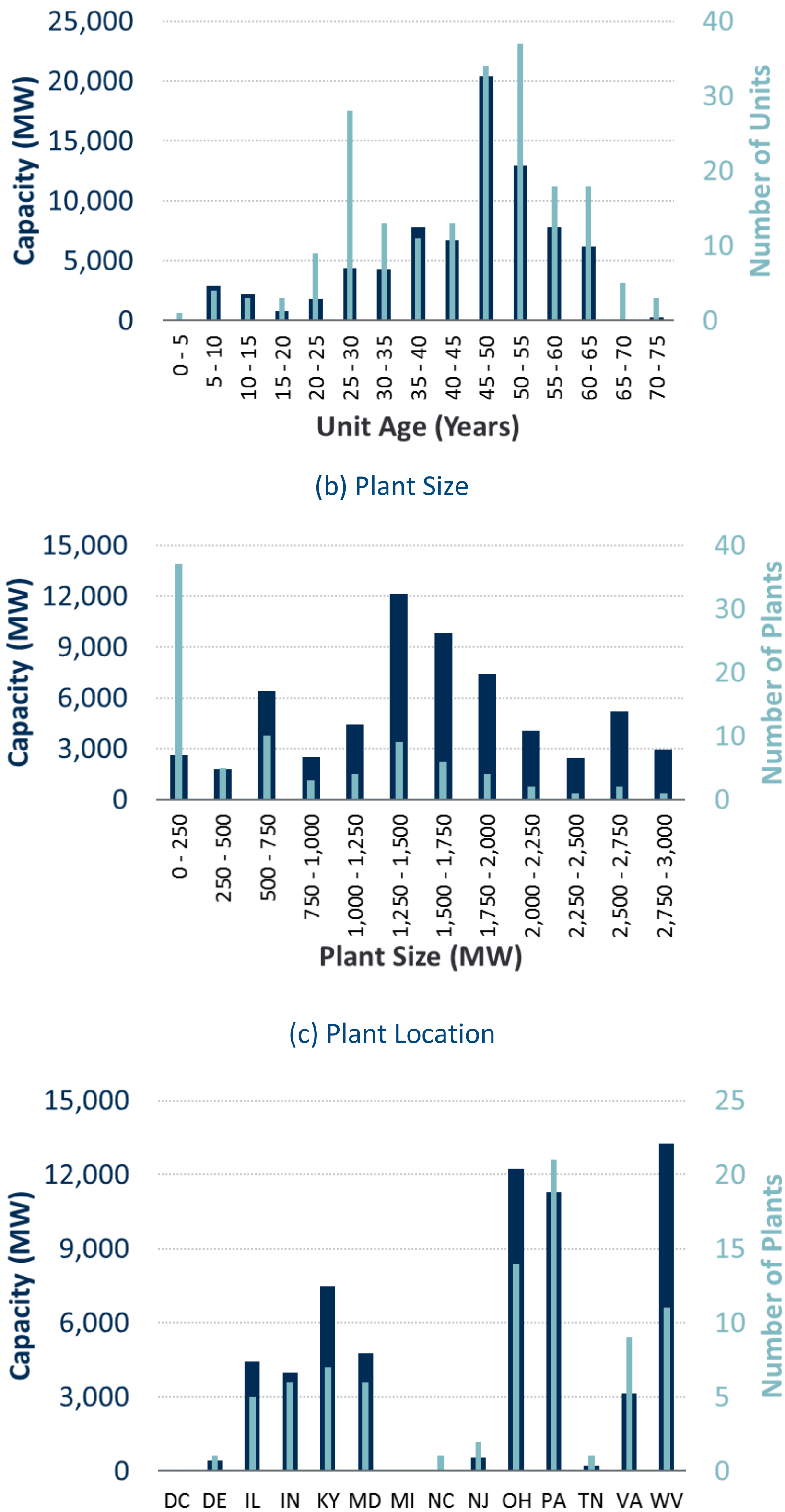
The fleet of existing coal plants in PJM comprises a much wider range of sizes, ages, and locations than the nuclear plants discussed above. We identified over 200 existing coal units currently in the PJM market at about 80 different plant sites. Figure 3 below shows the age, size, and locations of these plants. Plant capacities range from less than 100 MW to nearly 3,000 MW with the average plant size of 750 MW across all plants and 1,100 MW for plants that are at least 100 MW. Plant ages also vary. Several plants were built in the last 10 years, and the oldest was constructed in 1942. Over half of the coal capacity is 35-55 years old.

Figure 3: Coal Fleet Characterization

(a) Unit Age

(b) Plant Size

(c) Plant Location



Source: ABB, Energy Velocity Suite, accessed January 15, 2020.

Our experience shows us that the primary drivers of cost variability for coal plants is the total capacity of the plant, the location, and the types of post-combustion controls installed at the plant, especially a flue-gas desulfurization (FGD) unit. The majority of coal plants have a dry lime or wet limestone FGD unit installed.

For these reasons, we set the characteristics of the representative coal plant in PJM to be a 45-year-old 1,200 MW plant (two 600 MW units) in West Virginia that burns Appalachian coal and has a wet limestone flue-gas desulfurization (FGD) unit. For the representative low-cost plant and representative high-cost plant, we varied the capacity of the plant. We assume that the representative high-cost plant is a 300 MW plant (two 150 MW units) and the representative low-cost plant is an 1,800 MW plant (two 900 MW units). Because most coal plants in PJM have some type of sulfur dioxide control technology and the vast majority of them are wet FGD units, we chose not to vary that assumption. While there is a significant age range across the plants, we assume the high and low plants are also 45 years old because we do not expect plants in the range of 35 – 55 years old to have significantly different costs solely due to their age.

We estimated the total annual costs for operating the representative coal plants using data recently released by the EIA and FERC.[22,23] We reviewed the O&M costs, ongoing capital spending, and cost relationships across a broad range of plant configurations and developed our cost estimates by accounting for differences in unit sizes, number of units at the site, and ages in the reported costs relative to the representative plants. Our adjustments to the reported costs included estimation of staffing requirements, consumption of FGD reagent and other items, and disposal of ash and FGD sludge. The costs of staffing and other fixed expenses account for the economies of scale associated with larger unit sizes and multiple units at a site. We then validated the results against proprietary data for similar operating coal plants. Based on our review of publicly available projections of fixed operating costs (such as the NREL Annual Technology Baseline) and the recent cost trends we have observed in the industry, we escalated the costs from 2020 to 2022 by 2.0% per year.[24]

Similar to the nuclear plants, we identified the costs that are includable in the Gross ACR and those included in the variable cost component of cost-based energy offers. A 45-year-old 1,200 MW coal plant would be expected to invest about $30 million per year into the systems directly attributable to electricity production, which based on PJM's market rules would have to be accounted for in the variable cost "maintenance adder." Assuming a 60% capacity factor, the maintenance adder increases variable costs by about $5/MWh.[25] Meanwhile, the Gross ACR estimate includes fixed operating costs that are not directly attributable to electricity production,

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22 EIA, Generating Unit Annual Capital and Life Extension Costs Analysis Final Report on Modeling Aging-Related Capital and O&M Costs, prepared by Sargent & Lundy, May 2018.

23 FERC, FERC Form No. 1, Plant Cost Data, 2014 through 2018.

24 This rate of cost escalation is consistent with our observations of recent trends in the industry.

25 Our estimate of a 60% capacity factor is based on our review of EPA data for coal plants similar to the representative plant. U. S. Environmental Protection Agency (EPA), National Electric Energy Data System (NEEDS), v6, 2019.

such as labor, administrative costs, preventative maintenance to auxiliary equipment (buildings, HVAC, water treatment), insurance, and support services.

We did not include property taxes for the representative coal plants because they are not likely to be significant for a 45-year-old coal plant. The property taxes actually paid would depend on the lesser of the remaining rate base or the fair market value, as negotiated with the local jurisdiction. In both cases, the property taxes are likely to be quite small based on the age of the plants and recent market conditions for coal plants in PJM.

Table 6 below shows that the estimated Gross ACR for the representative coal plant is $80/MW-day with a range of $74/MW-day to $166/MW-day (in 2022 dollars). The variable costs are similar across plant ranging from $9.17/MWh to $9.56/MWh (in 2022 dollars).

Table 6: Estimated 2022 Costs for Existing Coal Plants in PJM
(in nominal dollars)

		Coal Plant		
	Units	**Representative Low-Cost Plant**	**Representative Plant**	**Representative High-Cost Plant**
Capacity	*Nameplate MW*	1,800	1,200	300
Gross ACR				
Labor	*$ million*	$23.6	$20.4	$11.2
Fixed Expenses	*$ million*	$24.8	$14.7	$7.0
Total	*$ million*	$48.4	$35.1	$18.2
Gross ACR	***$/MW-day***	**$74**	**$80**	**$166**
Variable Costs				
Operating Costs	*$/MWh*	$4.37	$4.77	$4.40
Maintenance Adder	*$/MWh*	$4.80	$4.80	$4.80
Variable O&M	***$/MWh***	**$9.17**	**$9.56**	**$9.20**

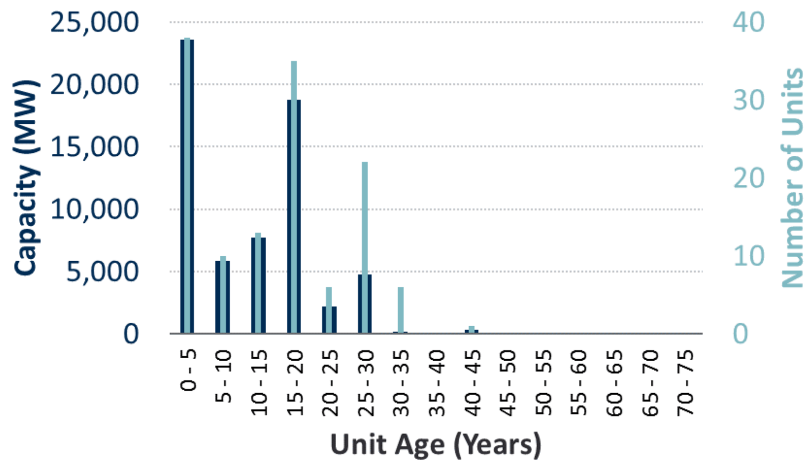
Note: Fixed Expenses include preventive maintenance on auxiliary equipment (buildings, HVAC, water treatment, freeze protection, etc.), information technology, miscellaneous supplies, support services, administrative and general, and insurance. We estimated the maintenance adder assuming a 60% capacity factor. If a different capacity factor will be assumed by PJM, the maintenance adder should be adjusted based on the ratio of 60% to the assumed capacity factor.

4. Natural Gas-Fired Combined-Cycle Plants

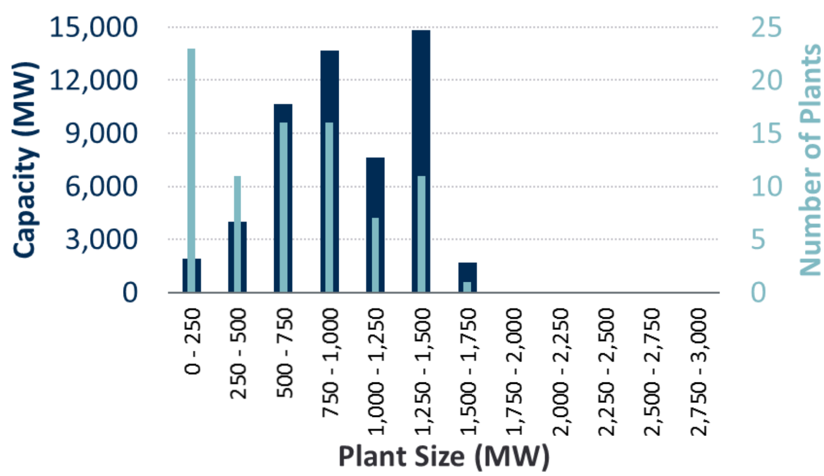
Most natural gas-fired combined-cycle (CC) plants and combustion turbine (CT) plants have been built more recently than coal plants with nearly all natural gas-fired resources built over the past 20 years and over 23,000 MW of CCs installed in the past 5 years alone. Figure 4 below shows the age, size, and locations of the existing gas CC plants. Most existing CCs that were built in the early 2000s are in the 500 MW to 1,000 MW range, while several recent projects exceed 1,000 MW. Most of the gas CCs have been built in regions with access to low-cost gas via pipeline or within production basins, including in Pennsylvania, Ohio, Virginia, and New Jersey. Most are equipped with Selective Catalytic Reduction (SCR) to reduce emissions of nitrogen oxides (NOx).

Figure 4: Natural Gas Combined-Cycle Fleet Characterization

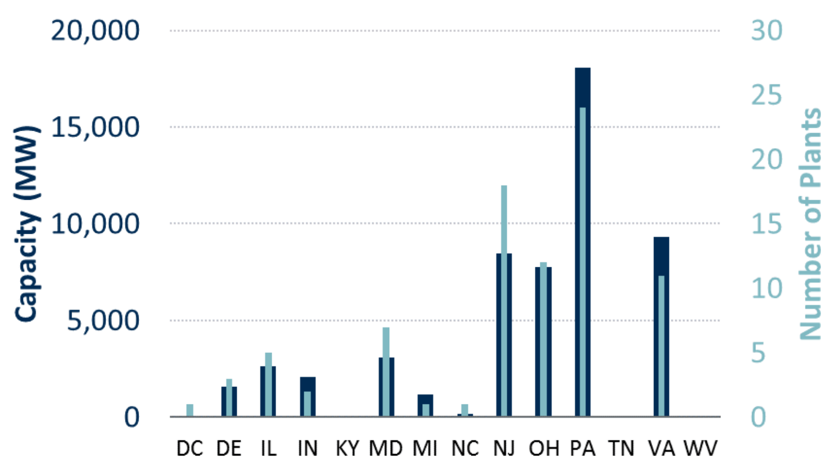
(a) Unit Age



(b) Plant Size



(c) Plant Location



Source: ABB, Energy Velocity Suite, accessed January 15, 2020.

The primary drivers of differences in costs for CCs tend to be the capacity of the units, the plant configuration, and the location, which affects labor costs and property taxes.

Based on the range of existing gas CCs, we specified the widely-representative plant to be a 15-year-old 750 MW plant with two F-class frame-type gas turbines and one steam turbine (2x1) in Pennsylvania. For the representative high-cost plant, we reduced the capacity to 360 MW to represent a 1x1 plant with a single F-class turbine, while we assumed the representative low-cost plant includes the larger H-class turbines in a 2x1 configuration for a total capacity of 1,100 MW (similar to the CC specifications developed for the PJM 2018 CONE Study).[26]

To estimate the costs of the representative plants, we relied primarily on cost estimates for gas CCs developed for the PJM 2018 CONE Study. Similar to how the costs are specified in the CONE Study, we included the hours-based major maintenance costs specified in Long-Term Service Agreements (LTSAs) under variable O&M costs as well as the operating costs associated with chemicals and consumables. The fixed costs for the gas CCs included labor, supplies, property taxes, and insurance costs.

We used the cost information from the CONE study to estimate components of the fixed O&M, variable O&M, and major maintenance for the representative low-cost plant (H-class 2 x 1). Other public sources and S&L's project database containing a broad range of CC configurations were used for estimating the cost components for the 750 MW and 360 MW F-class representative plants.[27,28] We adjusted the cost data in the public sources to account for differences in turbine sizes, configurations, locations, and ages relative to the representative plants and validated the results against proprietary data for similar plants in operation. These adjustments accounted for staffing requirements and the economies of scale associated with larger turbine sizes and multiple turbines at a site. The costs of major maintenance and consumables were derived using a 60% capacity factor, representative of CCs in PJM.[29] Property taxes were estimated using the rates in the CONE study for WMACC (Pennsylvania). We escalated the cost estimates from 2020 to 2022 by 2.0% per year based on our review of publicly available projections of fixed operating costs (such as the NREL Annual Technology Baseline) and the recent cost trends we have observed in the industry.

Table 7 below shows that the Gross ACR for the representative plant is $56/MW-day, which is slightly higher than the Gross ACR of the representative low-cost plant ($55/MW-day). Our cost estimates are significantly higher for the smaller 360 MW representative high-cost plant

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26 Newell, et al., PJM Cost of New Entry Combustion Turbines and Combined-Cycle Plants with June 1, 2022 Online Date, April 2018. ("PJM 2018 CONE Study")

27 U.S. Energy Information Administration, Cost and Performance Estimates for New Utility-Scale Electric Power Generating Technologies, prepared by Sargent & Lundy, December 2019.

28 FERC, FERC Form 1, Plant Cost Data, 2014 through 2018.

29 Monitoring Analytics, 2019 State of the Market Report for PJM, Section 5 – Capacity Market, Table 5-28, March 12, 2020, p. 292. Available at: http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2019/2019-som-pjm-sec5.pdf

($79/MW-day) due to the reduced economies of scale. The variable O&M costs for these resources are similar in the range of $2.24/MWh to $2.57/MWh.

Table 7: Estimated 2022 Costs for Existing Natural Gas-Fired Combined-Cycle Plants in PJM
(in nominal dollars)

		Natural Gas Combined-Cycle Plant		
	Units	**Representative Low-Cost Plant**	**Representative Plant**	**Representative High-Cost Plant**
Capacity	*Nameplate MW*	1,100	750	360
Gross ACR				
Labor	*$ million*	$6.4	$4.5	$3.5
Fixed Expenses	*$ million*	$7.8	$5.5	$4.3
Property Taxes	*$ million*	$2.0	$1.3	$0.6
Insurance	*$ million*	$5.9	$4.0	$1.9
Total	*$ million*	$21.9	$15.3	$10.3
Gross ACR	***$/MW-day***	**$55**	**$56**	**$79**
Variable Costs				
Operating Costs	*$/MWh*	$0.71	$0.49	$0.91
Maintenance Adder	*$/MWh*	$1.53	$2.08	$1.61
Variable O&M	***$/MWh***	**$2.24**	**$2.57**	**$2.53**

Note: Fixed Expenses include preventive maintenance on auxiliary equipment (buildings, HVAC, water treatment, freeze protection, etc.), information technology, miscellaneous supplies, support services, and administrative and general. We estimated the maintenance adder assuming a 60% capacity factor. If a different capacity factor will be assumed by PJM, the maintenance adder should be adjusted based on the ratio of 60% to the assumed capacity factor.

5. Natural Gas-Fired Combustion Turbines

Natural gas-fired CT plants tend to have a wider range of sizes due to differences in the turbine technology and the number of turbines installed at each plant. As shown in Figure 5 below, the majority of CT plants are less than 100 MW with the most overall capacity in the 500 – 750 MW range, and most were built 15 to 20 years ago. The states with the most CTs include New Jersey, Illinois, Pennsylvania, and Ohio. Unlike gas CCs, most CTs are not built with an SCR unit.

The range of costs of the CTs are primarily driven by the capacity of the resources (based on the turbine type and number of turbines) and their location.

We specified the representative plant to be a 15 year old 320 MW CT plant with two F-class turbines (160 MW each) located in Illinois. We selected a larger 640 MW CT plant with eight E-class turbines (80 MW each) for the representative-low plant and a 100 MW CT with two LM6000 aeroderivative turbines (50 MW each) for the representative-high plant.

To estimate costs, we reviewed cost estimates reported by the PJM 2018 CONE Study, the EIA cost estimates, and S&L's project database.[30,31] We then developed the cost estimates for existing CTs similar to the representative plants by adjusting the publicly reported costs for differences in turbine sizes, configurations, locations, and ages. We validated the results of our cost estimate against proprietary data for similar plants in operation. The adjustments account for staffing requirements and the economies of scale associated with larger turbine sizes and multiple turbines at a site. Property taxes were estimated using the rates in the CONE study for RTO (Illinois). We escalated the cost estimates from 2020 to 2022 by 2.0% per year based on our review of publicly available projections of fixed operating costs (such as the NREL Annual Technology Baseline) and the recent cost trends we have observed in the industry.

The E-class and F-class turbines operating as peaking units would be expected to trigger major maintenance events based on the number of starts. For this reason, we estimated the variable cost maintenance adder assuming a 10% capacity factor and 12 hours of operation per start.[32] The LM6000 turbines would likely trigger major maintenance based on hours of operation such that their maintenance adder is independent of the number of starts per year.

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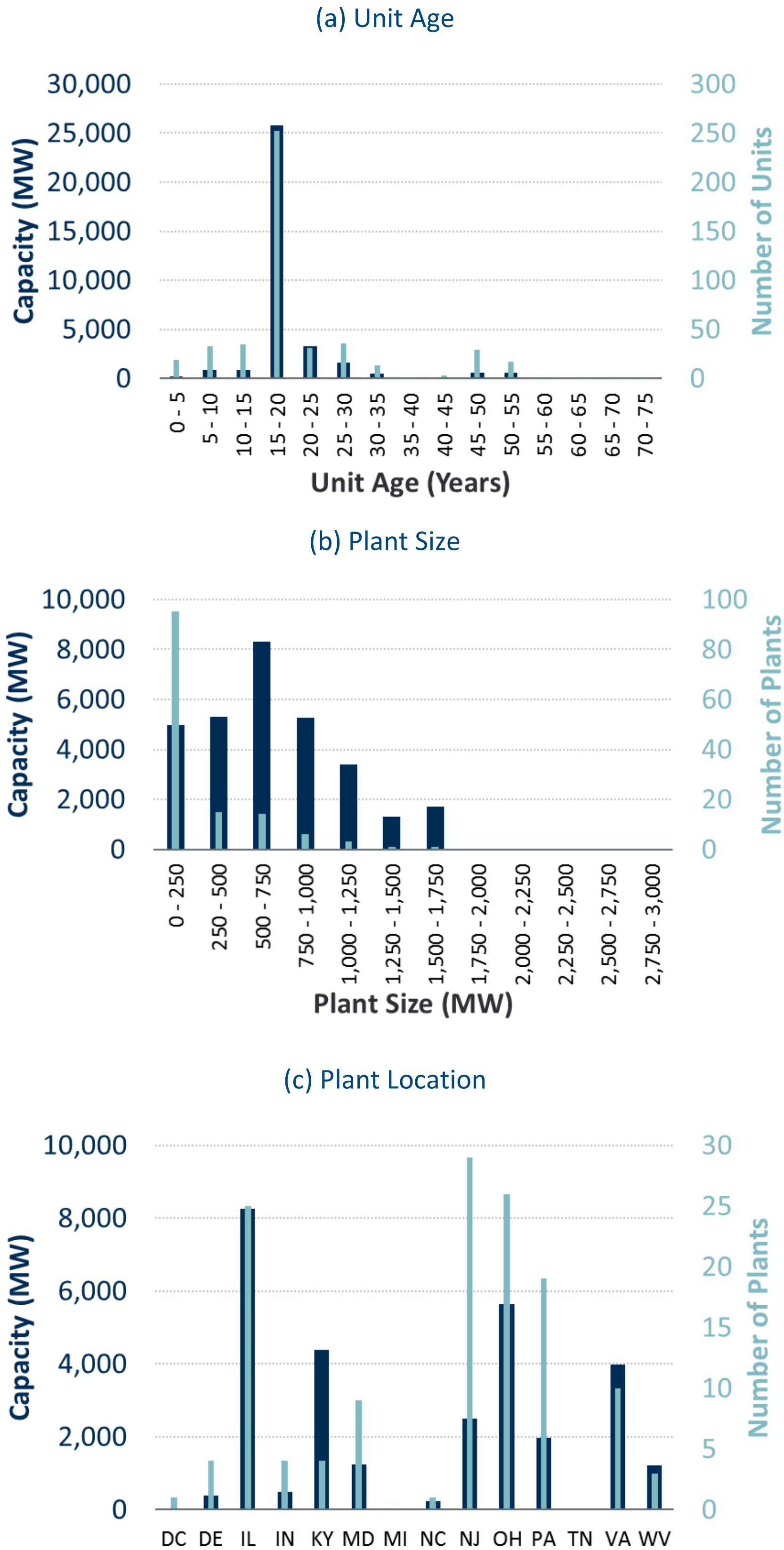
30 Newell, et al., PJM Cost of New Entry Combustion Turbines and Combined-Cycle Plants with June 1, 2022 Online Date, April 2018. Available at: https://brattlefiles.blob.core.windows.net/files/13896_20180420-pjm-2018-cost-of-new-entry-study.pdf

31 U.S. Energy Information Administration, Cost and Performance Estimates for New Utility-Scale Electric Power Generating Technologies, prepared by Sargent & Lundy, December 2019.

32 We assume 12 hours per start primarily based on the average operation hours per start estimated in the PJM 2018 VRR Curve Study (11 hours per start). Newell, et al., Fourth Review of PJM's Variable Resource Requirement Curve, April 19, 2018, p. 11. Available at: http://files.brattle.com/files/13894_20180420-pjm-2018-variable-resource-requirement-curve-study.pdf

Figure 5: Natural Gas Combustion Turbine Fleet Characterization



Source: ABB, Energy Velocity Suite, accessed January 15, 2020.

Table 8 below shows the resulting Gross ACR and variable costs for the CT plants. The Gross ACR for the representative plant is $50/MW-day, with a range of $42/MW-day to $65/MW-day (in 2022 dollars). The variable costs for the CTs range from $4.98/MWh to $7.54/MWh (in 2022 dollars).

Table 8: Estimated 2022 Costs for Existing Natural Gas-Fired Combustion Turbine Plants in PJM
(in nominal dollars)

		Natural Gas Combustion Turbine Plant		
	Units	Representative Low-Cost Plant	Representative Plant	Representative High-Cost Plant
Capacity	*Nameplate MW*	640	320	100
Gross ACR				
Labor	*$ million*	$1.6	$1.3	$0.9
Fixed Expenses	*$ million*	$1.3	$1.1	$0.8
Property Taxes	*$ million*	$3.8	$1.9	$0.1
Insurance	*$ million*	$3.0	$1.5	$0.6
Total	*$ million*	$9.8	$5.8	$2.4
Gross ACR	***$/MW-day***	**$42**	**$50**	**$65**
Variable Costs				
Operating Costs	*$/MWh*	$0.39	$0.39	$0.89
Maintenance Adder	*$/MWh*	$7.16	$7.16	$4.09
Variable O&M	***$/MWh***	**$7.54**	**$7.54**	**$4.98**

Note: Fixed Expenses in the Gross ACR includes preventive maintenance on auxiliary equipment (buildings, HVAC, water treatment, freeze protection, etc.), information technology, miscellaneous supplies, support services, and administrative and general. We estimated the maintenance adder assuming a 10% capacity factor. If a different capacity factor will be assumed by PJM, the maintenance adder should be adjusted based on the ratio of 10% to the assumed capacity factor.

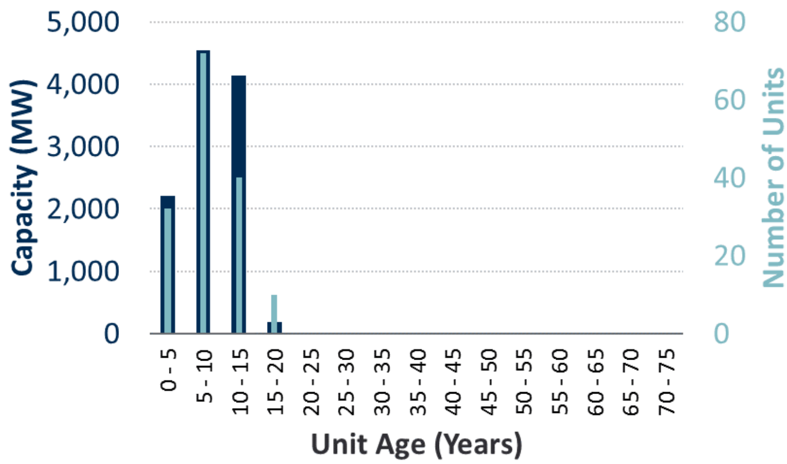
6. Onshore Wind Plants

Over the past 15 years, nearly 14,000 MW of onshore wind plants have been built in PJM. As shown in Figure 6 below, the majority of these plants are relatively small (less than 25 MW), but 15 have exceeded 200 MW. Most of the smaller plants are located in Pennsylvania and Ohio, while the larger ones are in Illinois and Indiana. The largest drivers of ongoing costs for wind plants tend to be their size and location.

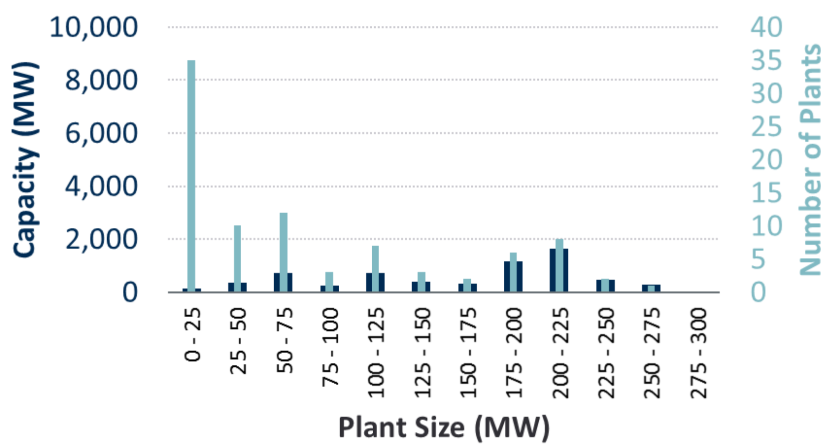
Based on the range of existing wind plants in PJM, we specified the representative plant to be a 60 MW wind farm (forty 1.5 MW turbines) in Pennsylvania that was built 10 years ago. For the higher end of the cost range, we reduced the capacity in half to 30 MW, and for the lower end of the range increased the capacity to 300 MW to represent some of the larger wind farms built in Illinois and Indiana.

Figure 6: Onshore Wind Fleet Characterization

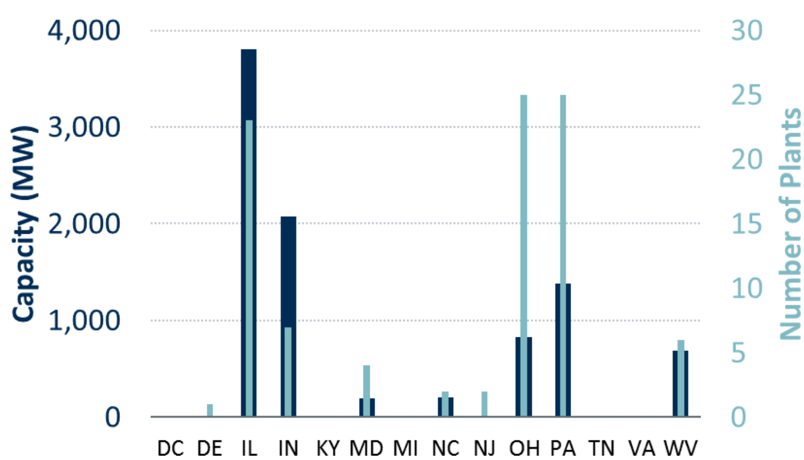
(a) Unit Age



(b) Plant Size



(c) Plant Location



Source: ABB, Energy Velocity Suite, accessed January 15, 2020.

We estimated fixed and variable O&M and capital costs for the representative wind plants by first reviewing recent public sources and S&L's project database.[33,34] We then developed the cost estimates for the representative plants accounting for differences in turbine sizes, number of turbines at the site, and ages relative to the representative plants, and validated the results against proprietary data for similar plants in operation. The representative plants were assumed to be exempt from property taxes or have a negotiated payment in lieu of taxes (PILOT) agreement with the local jurisdiction for a significantly reduced rate. We escalated the cost estimates from 2020 to 2022 by 2.0% per year based on our review of publicly available projections of fixed operating costs (such as the NREL Annual Technology Baseline) and the recent cost trends we have observed in the industry.

Table 9 below shows the resulting Gross ACR for the representative plant of $83/MW-day, with a range of $76/MW-day to $128/MW-day (in 2022 dollars). We assumed that all of the costs necessary to operate a wind plant (and a solar PV plant) are fixed and belong in the Gross ACR, with no variable costs. The costs do not vary with production, say in a windier year or a year with more curtailment and cannot be considered "directly attributable to the production of electricity" per PJM's standard for variable costs.

Table 9: Estimated 2022 Costs for Existing Onshore Wind Plants in PJM
(in nominal dollars)

		Onshore Wind Plant		
	Units	**Representative Low-Cost Plant**	**Representative Plant**	**Representative High-Cost Plant**
Capacity	*Nameplate MW*	300	60	30
Gross ACR				
Labor	*$ million*	$2.5	$0.5	$0.4
Fixed Expenses	*$ million*	$5.9	$1.3	$1.0
Total	***$ million***	**$8.4**	**$1.8**	**$1.4**
Gross ACR	***$/MW-day***	**$76**	**$83**	**$128**
Variable Costs				
Operating Costs	*$/MWh*	$0.00	$0.00	$0.00
Maintenance Adder	*$/MWh*	$0.00	$0.00	$0.00
Variable O&M	***$/MWh***	**$0.00**	**$0.00**	**$0.00**

33 U.S. Energy Information Administration, Cost and Performance Estimates for New Utility-Scale Electric Power Generating Technologies, prepared by Sargent & Lundy, December 2019.

34 National Renewable Energy Laboratory, 2019 Annual Technology Baseline, 2019.

7. Large-Scale Solar Photovoltaic Plants

Large-scale solar photovoltaic (PV) plants tend to be fairly small in PJM, with most plants under 10 MW and a few in the 50 – 100 MW range, as shown in Figure 7 below. All of the solar PV plants have been built in the past 15 years, with the most capacity added in New Jersey and North Carolina. Similar to wind plants, the capacity and location tend to have the most significant impacts on the costs of solar PV plants.

Based on our survey of the existing solar PV plants, we set the representative plant as a 10 MW single-axis tracking solar PV plant in New Jersey built 5 years ago. For the representative high-cost plant, we reduced the capacity to 2 MW and for the representative low-cost plant increased the capacity to 80 MW and located it in North Carolina.

We estimated fixed and variable O&M and capital costs for the representative solar PV plants by reviewing recent public sources and S&L's project database.[35,36] We then developed the cost estimates for the representative solar PV plants accounting for differences in the solar panel type, tracking type, plant size, and ages relative to the representative plants and validated the results against proprietary data for similar plants in operation. The representative plants were assumed to be exempt from property taxes or have a negotiated payment in lieu of taxes (PILOT) agreement with the local jurisdiction for a significantly reduced rate. We escalated the cost estimates from 2020 to 2022 by 2.0% per year based on our review of publicly available projections of fixed operating costs (such as the NREL Annual Technology Baseline) and the recent cost trends we have observed in the industry.

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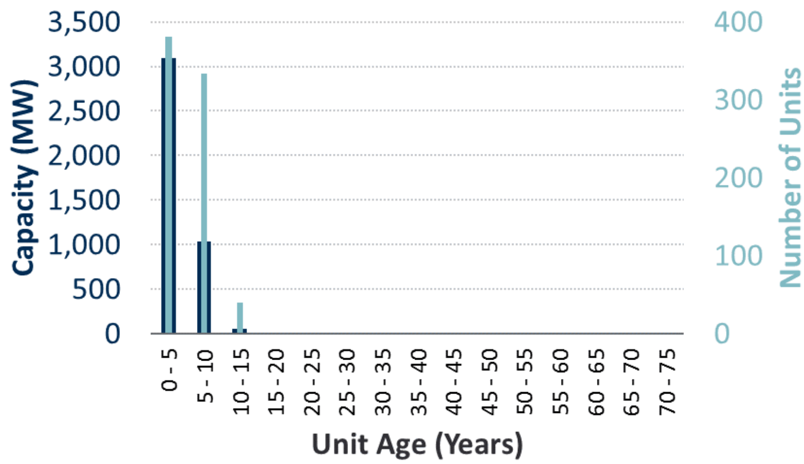
35 National Renewable Energy Laboratory, 2019 Annual Technology Baseline, 2019.

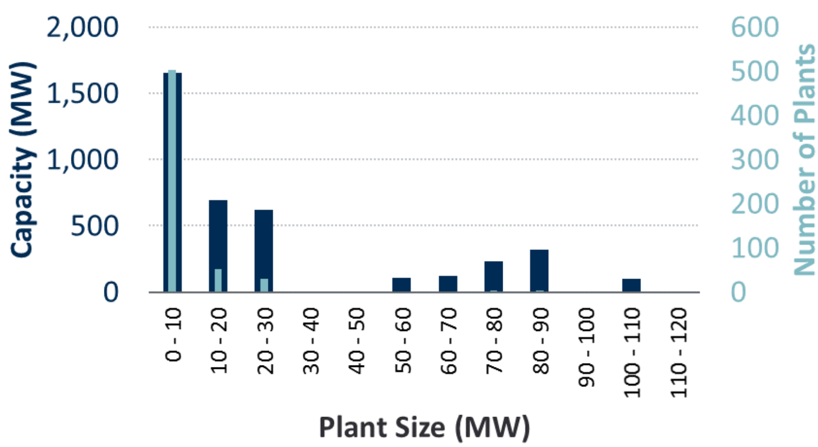
36 Lawrence Berkeley National Laboratory, Utility-Scale Solar: Empirical Trends in Project Technology, Cost, Performance, and PPA Pricing in the United States – 2019 Edition, December 2019. Available at: https://emp.lbl.gov/sites/default/files/lbnl_utility_scale_solar_2019_edition_final.pdf

Figure 7: Large-Scale Solar Photovoltaic Fleet Characterization

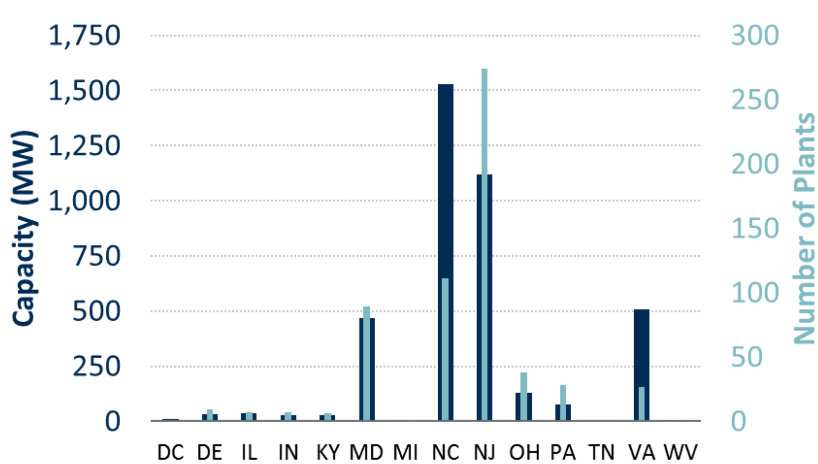
(a) Unit Age



(a) Plant Size



(a) Plant Location



Source: ABB, Energy Velocity Suite, accessed January 15, 2020.

Table 10 below shows that we estimated a Gross ACR for the representative solar PV plant of $40/MW-day with a range of $29/MW-day for the larger plant to $60/MW-day for the smaller plant (in 2022 dollars). We assumed that all of the costs necessary to operate a solar PV plant are fixed costs that are not directly attributable to the production of electricity, and thus did not include any variable costs for the solar PV plants.

Table 10: Estimated 2022 Costs for Existing Large-Scale Solar Photovoltaic Plants in PJM
(in nominal dollars)

		Large-Scale Solar Photovoltaic Plant		
	Units	**Representative Low-Cost Plant**	**Representative Plant**	**Representative High-Cost Plant**
Capacity	*Nameplate MW*	80	10	2
Gross ACR				
Labor	*$ million*	$0.3	$0.06	$0.02
Fixed Expenses	*$ million*	$0.5	$0.09	$0.03
Total	*$ million*	$0.8	$0.15	$0.04
Gross ACR	***$/MW-day***	**$29**	**$40**	**$60**
Variable Costs				
Operating Costs	*$/MWh*	$0.0	$0.0	$0.0
Maintenance Adder	*$/MWh*	$0.0	$0.0	$0.0
Variable O&M	***$/MWh***	**$0.00**	**$0.00**	**$0.00**

8. Behind-the-Meter Diesel Generators

Based on a survey of the existing active demand response resources in the PJM market, we found that the average capacity of behind-the-meter diesel generators is about 600 kW and that they are primarily located at commercial facilities. These resources tend to hold emergency operating permits that allow them only to operate when called upon during emergency system conditions. For that reason, they are not expected to operate frequently and are likely controlled (for demand response purposes) by a demand response aggregator. Their primary annual cost is an annual maintenance contract to ensure the facility remains operational in case it is called upon. Property taxes for the commercial facility are assumed to be insignificantly affected by the installation of a behind-the-meter backup diesel generator, so we assume them to be zero.

Based on our discussions with vendors of diesel generators of this scale, we estimate that their annual maintenance contracts cost about $1/kW, which translates to $3/MW-day.

We would expect that the demand response aggregator that operates the diesel generator during emergency conditions to require a payment that is a portion of the capacity market revenues. Our past experience suggests payment rates of 20 – 30% of the capacity market prices earned. We have not included these costs due to a lack of transparency on how much they are likely to require and the uncertainty in future capacity market prices. Moreover, these costs are likely small relative to the reliability benefits of owning a backup generator that are not accounted for in Net ACRs. Protecting against local distribution outages is usually the primary driver for a commercial facility to install a backup generator behind the meter.

III. Net CONE for New Energy Efficiency

PJM requested that we estimate the net cost of new entry (Net CONE) for new EE resources offering into the capacity market. Estimating a representative Net CONE for EE is not as straightforward as doing so for new, standardized generation technologies, such as natural gas-fired CCs and CTs. EE resources represent energy-saving measures nearly as diverse as the uses of electricity in our society. To develop a single representative EE Net CONE, we had to define a portfolio of EE resources that is representative of that diversity and for which there is accurate, publicly available cost information, then take an average across that portfolio. This approach may result in a value that differs significantly from individual resources' actual net costs. However, as we demonstrate below, the prevailing net costs of EE measures are generally lower than typical capacity market prices (presumably reflecting "low-hanging fruit" opportunities to save energy cost-effectively) such that the vast majority of EE resources should clear the market no matter where the default offer is set.

A. Identifying a Representative EE Portfolio

In the 2021-2022 Base Residual Auction, over 2,800 MW (UCAP) of EE resources cleared across PJM.[37] Some of this capacity is offered by utilities and the rest by competitive energy service companies. Even that offered by competitive service companies, however, is partly based on helping customers take advantage of utility incentives. Because of the widespread relevance of utility programs for EE, as well as the availability of utility EE cost and benefit data (due to their state regulatory oversight), we use utility EE programs to develop our representative EE portfolio.

[37] The total EE resources that cleared the 2021/22 BRA increased by 1,100 MW from the previous auction. PJM, 2021/2022 RPM Base Residual Auction Results, https://pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2021-2022/2021-2022-base-residual-auction-report.ashx?la=en, p. 11.

Table 11: EE Programs by Utility

Customer Class	Program Name	Included/ Excluded	Annual Energy Savings *MWh*	Peak Demand Savings *MW*
BGE				
Residential	Residential Lighting	Included	140,707	19.5
Residential	Appliance Rebates	Included	3,251	0.7
Residential	Home Performance with ENERGY STAR	Included	3,933	1.1
Residential	HVAC Rebates	Included	10,860	3.2
Residential	ENERGY STAR for New Homes	Included	6,377	2.5
C&I	Small Business Energy Solutions	Included	26,000	5.5
C&I	Prescriptive	Included	62,000	3.5
C&I	Custom	Included	21,000	5.5
C&I	Building Tune-up	Included	4,000	1.0
C&I	Instant Savings	Included	28,000	10.0
Residential	Appliance Recycling	Excluded	8,639	1.5
Residential	Quick Home Energy Check-up	Excluded	11,421	0.1
Residential	Smart Thermostats	Excluded	7,412	1.0
Residential	Smart Energy Manager	Excluded	46,102	10.4
Residential	Smart Energy Rewards	Excluded	1,573	115.2
C&I	Combined Heat and Power	Excluded	24,000	3.6
ComEd				
Residential	Appliance Rebates	Included	5,580	0.9
Residential	Elementary Energy Education	Included	1,734	0.2
Residential	Home Energy Assessments	Included	8,875	0.9
Residential	HVAC and Weatherization	Included	18,770	4.8
Residential	Multifamily - Tenant Area	Included	3,268	0.3
Residential	Res Fridge and Freezer	Included	26,185	2.6
Residential	Residential New Construction	Included	547	0.3
C&I	AirCare Plus	Included	2,786	0.3
C&I	Business Instant Lighting Discount	Included	282,451	51.1
C&I	Business New Construction	Included	43,303	8.6
C&I	Business Custom	Included	26,725	3.6
C&I	Data Centers	Included	19,153	1.8
C&I	Industrial Systems	Included	39,434	4.9
C&I	Retro- Commissioning	Included	25,215	0.5
C&I	Business Standard	Included	230,289	25.8
Residential	Meter Genius Pilot	Excluded	n/a	n/a
Residential	Res ES Lighting (Carryover)	Excluded	87,810	9.9
C&I	Business Instant Lighting Discount (Carryover)	Excluded	31,002	6.3
C&I	Energy Analyzer	Excluded	59,217	n/a
C&I	Strategic Energy Management Pilot	Excluded	7,160	n/a
PPL				
Residential	Efficient Lighting	Included	128,036	17.4
Residential	EE Kits & Education	Included	11,829	1.1
Residential	EE Home	Included	18,802	3.6
Residential	SEEE	Included	6,024	0.6
C&I	All Programs	Included	162,377	22.7
Residential	Appliance Recycling	Excluded	10,731	1.6
Residential	Home Energy Education	Excluded	30,311	5.3
Residential	LI WRAP	Excluded	14,412	1.6

Our first step was therefore to identify representative utilities with sufficiently detailed publicly available data on the cost and performance of EE programs to analyze their Net CONE. Based on the public reports we reviewed, we found sufficient program-level data for the following three PJM utilities that represent the largest utility programs in their respective states (hence serve as good representatives): Baltimore Gas and Electric (BGE) in Maryland, Commonwealth Edison (ComEd) in Illinois, and Pennsylvania Power and Light (PPL) in Pennsylvania.[38]

Our next step was to identify the relevant programs within each of these utilities. The three utilities provide information on their overall EE portfolio on a program-by-program basis (ranging from eight to 20 programs per utility), including a total of 44 programs with cumulative peak demand savings of 361 MW. We excluded 14 programs (157 MW) that PJM instructed us would not qualify for offering capacity or would participate in the capacity market as demand response, not EE.[39] Table 11 above shows the EE programs reported for each utility that we considered in our analysis and whether or not they are included in the calculation of Net CONE.

B. Net CONE Analysis Approach

Net CONE represents the net cost of providing new resources into the capacity market. It is the capacity market revenue that a resource would need to earn to justify the initial investment costs that are not covered by other benefits. The Net CONE calculation therefore includes the total economic costs of the EE programs minus all (non-capacity) cost savings:

- EE program costs spent by utilities, including the costs of providing incentives to participants and administering the programs;
- Incremental out-of-pocket costs to the participant of implementing the EE measure, compared to installing less efficient equipment or retaining old equipment;
- Cost savings from reduced purchases of energy, measured at the wholesale market price; and,
- Cost savings from reduced investment in the transmission and distribution (T&D) system associated with limiting load growth.

These costs and benefits (in the form of cost savings) are consistent with utilities' Total Resource Cost tests, but we exclude capacity cost savings since the capacity value needed for economic viability is what we are solving for when we calculate the Net CONE. This perspective differs from that of an individual participant in an EE program, who pays only a portion of the costs (with the remainder covered by utility program incentives) and receives benefits from reduced energy demand based on its retail rates. Calculating the benefits of reduced energy based on the retail

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38 We reviewed publicly-available reports on EE programs in Delaware, Ohio, Illinois, Indiana, Maryland, New Jersey, Pennsylvania, Virginia, and Washington D.C. Reports on EE programs in Pennsylvania and Maryland included sufficient data to calculate Net CONE for all of the utilities in their state.

39 We also excluded programs with insufficient cost or performance data to calculate Net CONE, as indicated by "(Carryover)" or "n/a" in the table.

rates is not the right approach because retail rates include a portion of the fixed T&D costs allocated to the participant. The reduction in demand following the addition of the EE programs does not avoid these costs from being incurred, but instead shifts them to other customers. For this reason, using the retail rate would overstate the resource cost savings of the EE programs. Retail rates also include the costs of procuring capacity, which would double count the value of reduced peak demand if included in the Net CONE calculation. For these reasons, the costs and benefits included in the Total Resource Cost test provide the right basis for evaluating the economics of EE programs as a source of wholesale capacity.

Applying these concepts to the portfolio of EE programs included in our sample required analyzing each program's utility and participant costs, annual and lifetime energy savings, estimated energy losses, and peak demand savings. Consistent with PJM rules, the relevant capacity for capacity market purposes is the customer peak savings (Retail MW) during EE performance hours grossed up by the assumed energy losses during peak periods to calculate the "nominated EE value" (ICAP MW), and then grossed up again by the PJM pool requirement of 1.087 to calculate the "UCAP value of EE."[40]

We identified the costs of each program eligible for participation as an EE resource based on the utilities' documentation and then converted the costs into a gross cost of new entry (Gross CONE) per MW of capacity. Much like the Gross CONE calculation for new generation resources, this calculation is performed on a levelized basis. The levelization considers the estimated lifetime of the resource, and levelizes costs using PJM's assumed discount rate for merchant generation of 8.2%. This discount rate properly values the risks related to future wholesale market value of the investment in EE programs.

Similar to generation resources, calculating Net CONE requires subtracting from Gross CONE the value of the resource in the wholesale energy market. For EE programs, the value is based on the savings from reduced wholesale energy purchases. We estimated the wholesale energy savings for the EE programs in our analysis based on the total annual energy savings in each load zone and the three-year historical (2017-19) load-weighted average prices in each zone. This approach is consistent with how PJM estimates the net energy revenues for existing and new generation resources. By applying the annual energy savings to the load-weighted average prices, we are assuming that the energy savings from the EE programs are distributed throughout the year in proportion to the overall load.

We also deducted the value of reduced T&D investment using the values assumed by each utility in its EE cost-effectiveness analysis. While these costs vary from utility to utility and are uncertain, so too are the network upgrade costs that are included in the Net CONE calculations for generation resources. The key difference from generation is that EE provides T&D investment savings by reducing customer load growth, whereas as new generation generally incurs T&D investment costs to make it deliverable.

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40 PJM, PJM Manual 18: PJM Capacity Market, Revision: 44, Section 4.4, pp. 78-82. Available at: https://www.pjm.com/~/media/documents/manuals/m18.ashx

Thus, we calculated the Net CONE for each EE program by subtracting the estimated wholesale energy savings and T&D savings from the Gross CONE. Finally, we calculated the capacity-weighted average of EE programs in our analysis to determine the Net CONE for the portfolio of EE resources.

C. Energy Efficiency Net CONE Results

Table 12 below summarizes the total peak demand savings in our analysis the energy and peak demand savings of the programs included in our analysis across the three utilities. We estimated the amount of wholesale energy savings and peak demand savings by grossing up the retail savings by the appropriate loss factor. The annual average energy savings of the EE programs in our analysis is 6,690 MWh per megawatt of peak demand savings.

Table 12: Energy and Peak Demand Savings of EE Programs by Utility

		Retail Savings				Losses		Wholesale Savings	
Utility	Programs	Peak Demand Savings	Annual Energy Savings	Lifetime Energy Savings	Average Lifetime	Average Losses	Peak Losses	Peak Demand Savings	Annual Energy Savings
	#	*Retail MW*	*GWh*	*GWh*	*years*	*%*	*%*	*MW ICAP*	*GWh*
BGE	10	53	306	4,774	16	6%	9%	57	324
ComEd	15	107	734	7,236	10	11%	26%	134	815
PPL	5	45	327	3,372	10	9%	9%	49	356
Total	**30**	**204**	**1,368**	**15,382**	**11**	**9%**	**18%**	**240**	**1,495**

We estimated that the average costs for the EE programs in our analysis are $1,812/kW ICAP (in 2022 dollars), as shown in Table 13 below.[41] We calculated that the Gross CONE for the portfolio

41 BGE: We take the annual programs costs based from the "All Ratepayers Test (TRC)" for 2018-2020. See "Errata to Baltimore Gas and Electric Company's 2018-2020 EmPOWER Program Filing," *In the Matter of Baltimore Gas and Electric Company's Energy Efficiency, Conservation and Demand Response Programs Pursuant to the EMPOWER Maryland Energy Efficiency Act of 2008,* No. 9154, (Maryland Public Utilities Commission Sept. 22, 2017), ECF. No. 826.

ComEd: We take the annual program costs from the Program Year 8 "IL TRC Costs." We relied on the results for the Energy Efficiency Portfolio Standard (EEPS) portion of its EE programs and excluded the Illinois Power Agency (IPA) portion to be consistent with ComEd's cost-effectiveness tests. See Navigant, ComEd Review of PY8 Total Resource Cost Test Assumptions, Energy Efficiency/Demand Response Plan: Plan Year 8 (PY8) (6/1/2015-5/31/2016), January 28 2019, accessed March 13, 2020. Available at: http://ilsagfiles.org/SAG_files/Evaluation_Documents/TRC_Reports/ComEd/ComEd_PY8_TRC_Report_2019-01-28_Final.pdf.

PPL: We take the annual program costs based on the Program Year 9 costs for "TRC NPV Costs." Because PPL did not report lifetime energy savings at the program level, we used the aggregate cross-program lifetime energy savings and annual energy savings to derive an implied lifetime of 10 years, which we of EE programs is $235/kW ICAP-year based on the program costs, the program lifetime, and the 8.2% discount rate shown below.

Table 13: Total Costs and Gross CONE of EE Programs by Utility

Utility	Total Costs *$ million*	Total Costs *$/kW ICAP*	Discount Rate *%*	Average Lifetime *years*	Gross CONE *$/kW ICAP-yr*
BGE	$112.2	$1,963	8.2%	16	$212
ComEd	$198.7	$1,484	8.2%	10	$205
PPL	$124.6	$2,529	8.2%	10	$345
Total	**$435.6**	**$1,812**	**8.2%**	**11**	**$235**

Note: Total costs and Gross CONE are weighted averages by program installed capacity.
All monetary values are in 2022 dollars.

As shown in Table 14 below, the EE programs result in energy savings of $177/kW ICAP-year. The avoided energy prices range from $26/MWh in ComEd to $34/MWh in BGE based on historical average prices for 2017 to 2019 provided by PJM. For avoided T+D costs, we estimated that the average savings to ratepayers due to the EE programs is $35/kW ICAP-year. The T&D cost savings utilized by the utilities in their cost effectiveness tests range from $33/kW-year for ComEd to $54/kW-year for BGE.[42] While there is significant uncertainty about the savings from avoided T+D costs due to EE programs, a study completed for the New Jersey EE programs found that the assumed savings range from $0/kW-year to $200/kW-year across multiple utilities.[43] The weighted-average savings used in our analysis, $41/kW-year, is on the conservative end of this range, and is similar to the value used by ISO-NE in its most recent calculation of EE Net CONE ($38/kW-year).[44]

then applied to each individual program for discounting. See NMR Group, Inc., et al., SWE Annual Report Act 129 Program Year 9, February 28, 2019, accessed March 13, 2020, http://www.puc.pa.gov/Electric/pdf/Act129/Act129-SWE_AR_Y9_022819.pdf.

Program costs were escalated by 2% per year to 2022 assuming the costs remain constant in real terms.

42 PPL did not report the assumed T&D cost savings in its report. We have assumed the average of the ComEd and BGE numbers, $44/kW-yr.

43 Rutgers Center for Green Building, Energy Efficiency Cost-Benefit Analysis Avoided Cost Assumptions, Technical Memo, May 1, 2019.

44 Concentric Energy Advisors, ISO-NE CONE and ORTP Analysis: An evaluation of the entry cost parameters to be used in the Forward Capacity Auction to be held in February 2018 ("FCA-12") and forward, January 13, 2017, p. 82. Available at: https://www.iso-ne.com/static-assets/documents/2017/01/cone_and_ortp_updates.pdf

Table 14: Energy and T&D Savings of EE Programs by Utility

Utility	Energy Savings				T&D Savings			
	Average Energy Price	Wholesale Annual Energy Savings	Annual Energy Savings	Annual Energy Savings	Avoided T+D Costs	Retail Peak Demand Savings	Annual T+D Savings	Annual T+D Savings
	$/MWh	*GWh*	*$ million*	*$/kW ICAP-yr*	*$/kW-yr*	*Retail MW*	*$ million*	*$/kW ICAP-yr*
BGE	$34.12	324	$11.1	$193	$53.95	53	$2.8	$50
ComEd	$26.40	815	$21.5	$161	$33.32	107	$3.6	$27
PPL	$28.11	356	$10.0	$203	$43.64	45	$2.0	$40
Total	**$28.54**	**1,495**	**$42.6**	**$177**	**$40.91**	**204**	**$8.4**	**$35**

Note: Averages are weighted by program installed capacity. Avoided T+D Costs are reported by the utilities per MW of peak reduction at the customer meter.

We calculated that the EE Net CONE is $23/kW ICAP-year (or $64/MW ICAP-day) based on the Gross CONE of $235/kW ICAP-year and subtracting out the energy cost savings ($177/kW ICAP-year) and T&D cost savings ($35/kW ICAP-year). We calculated the EE Net CONE in terms of UCAP is $58/MW UCAP-day. The relationship between ICAP and UCAP reflects the 9% gross-up for the PJM pool requirement of 1.087.

Table 15: Net CONE of EE Programs by Utility

Utility	Gross CONE	Annual Energy Savings	Annual T+D Savings	Net CONE	Net CONE	Net CONE
	$/kW ICAP-yr	*$/kW ICAP-yr*	*$/kW ICAP-yr*	*$/kW ICAP-yr*	*$/MW ICAP-day*	*$/MW UCAP-day*
BGE	$212	$193	$50	-$31	-$86	-$79
ComEd	$205	$161	$27	$18	$48	$45
PPL	$345	$203	$40	$102	$278	$256
Total	**$235**	**$177**	**$35**	**$23**	**$64**	**$58**

Note: Net CONE equals Gross CONE minus the sum of Annual Energy Savings and Annual T+D Savings.

BOSTON
BRUSSELS
LONDON
MADRID
NEW YORK
ROME
SAN FRANCISCO
SYDNEY
TORONTO
WASHINGTON

THE Brattle GROUP

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)**

VERIFICATION

Samuel A. Newell, being first duly sworn, deposes and states that he is the Samuel A. Newell referred to in the foregoing document entitled "Affidavit of Samuel A. Newell, John M. Hagerty, and Sang H. Gang 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 17th day of March 2020.

Virginia Quinn Rundell
Notary Public

My Commission expires: 2/17/2023

VIRGINIA QUINN RUNDELL
NOTARY PUBLIC
COMMONWEALTH OF MASSACHUSETTS
MY COMMISSION EXPIRES 2/17/2023

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)**

VERIFICATION

John M. Hagerty, being first duly sworn, deposes and states that he is the John M. Hagerty referred to in the foregoing document entitled "Affidavit of Samuel A. Newell, John M. Hagerty, and Sang H. Gang 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.

____

Subscribed and sworn to before me, the undersigned notary public, this 17 day of March 2020.

____
Notary Public

My Commission expires: June 8 2020

OLUWAFEMI IJITI
NOTARY PUBLIC
PRINCE GEORGE'S COUNTY
MARYLAND
MY COMMISSION EXPIRES JUNE 8, 2020

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)**

VERIFICATION

Sang H. Gang, being first duly sworn, deposes and states that he is the Sang H. Gang referred to in the foregoing document entitled "Affidavit of Samuel A. Newell, John M. Hagerty, and Sang H. Gang 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.

Subscribed and sworn to before me, the undersigned notary public, this 16 day of March 2020.

Brenda Campbell

Notary Public

OFFICIAL SEAL
BRENDA CAMPBELL
NOTARY PUBLIC - STATE OF ILLINOIS
MY COMMISSION EXPIRES:08/27/23

My Commission expires: 08/27/2023

Attachment E

Keech 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 No. ER18-1314
PJM Interconnection, L.L.C.	)	Docket No. EL18-178 (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 Vice President, Market Operations for PJM Interconnection, L.L.C. ("PJM"). I am submitting this affidavit on behalf of PJM in support of its compliance filing, as directed by the Federal Energy Regulatory Commission ("FERC") in its December 19 Order.[1]

B. Work Experience and Responsibilities

2. I have served in my current position since 2019 and previously served as Executive Director or Senior Director of Market Operations since 2013 where I had similar responsibilities. The Market Operations Departments at PJM are responsible for

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1 *Calpine Corp. v. PJM Interconnection, L.L.C.*, 169 FERC ¶ 61,239 (2019) ("December 19 Order").

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, the Interregional Market Operations Department, the Demand Response Operations Department, the Performance Compliance Department, the Advanced Analytics Department, the Applied Innovation Department, and the Renewable Services 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 Vice President, Market Operations, 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 Vice President 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. Establishing Default MOPR Floor Offer Prices for Capacity Resources with Actionable Subsidies

a. Default MOPR Floor Offer Prices for New Entry Capacity Resources shall be Based on the Construction and Development Costs of that Resource Type

5. As directed by the December 19 Order, PJM is proposing default Minimum Offer Price rule ("MOPR") Floor Offer Prices for New Entry Capacity Resources. PJM will annually post the default values for 10 distinct generation resource types (plus generation-backed Demand Resources) 150 days in advance of the relevant Reliability Pricing Model ("RPM") Auction. For New Entry Capacity Resources, these values will be based on an estimate of the "nominal-levelized" annual cost to construct and develop each resource type referred to as Gross Cost of New Entry ("CONE") from which PJM will subtract the estimated net energy and ancillary services ("E&AS") revenues for each resource type and Zone to determine the net Cost of New Entry ("Net CONE"). It is appropriate to use 100% of the Net CONE value as the default MOPR Floor Offer Price as it represents the cost to construct and develop each Capacity Resource with State Subsidy.

6. PJM is proposing to establish in the Tariff the default Gross CONE value for each resource type, shown in Table 1. The Tariff-stated values will be used for the 2022/2023 Delivery Year Base Residual Auction. The table includes the net E&AS revenues and the resulting MOPR Floor Offer prices derived from the Gross CONE and average of zonal net E&AS revenues for each resource type. The zonal net E&AS values and resultant Net CONE values for each zone are shown in the accompanying workbook in Appendix A. Table 1 uses the average of all of the zonal Net E&AS values to determine the RTO-wide averages for illustrative purposes. These values will not be used in practice.

7. The Gross CONE and net E&AS revenue offset values presented in Table 1 are expressed in terms of nameplate megawatts ("MW") rating, while the MOPR Floor Offer Prices are expressed on an Installed Capacity ("ICAP") MW basis where the ICAP MW of a resource represents the capacity value of the resource or the maximum MW level at which a resource may participate as a Capacity Resource.

8. The ICAP MW value for solar photovoltaic ("PV") (Tracking), solar PV (Fixed), onshore wind and offshore wind is assumed to be 60%, 42%, 17% and 26%, respectively, of the resources nameplate MW, based on the class average capacity value for these resource types. With the exception of offshore wind, these values are based on average historical data for individual solar and wind projects in PJM.[2] For offshore wind, the 26% used is consistent with the range in data models that have been confidentially

[2] *See Class Average Capacity Factors: Wind and Solar Resources*, PJM Interconnection, L.L.C. (June 4, 2017), https://www.pjm.com/-/media/planning/res-adeq/class-average-wind-capacity-factors.ashx?la=en.

provided to PJM in support of proposed offshore wind generation projects in the PJM interconnection queue.

9. The ICAP MW value of the battery energy storage resource of Table 1 is assumed to 40% of the resource's nameplate rating because the Gross CONE of the battery energy storage resource was developed for a resource capable of providing output at its nameplate MW for a 4-hour continuous period before depleting its entire stored energy capability. Currently, PJM uses a 10-hour period of continuous operation as the minimum requirement for Capacity Storage Resources. Because the reference storage resource can only provide 4-hours of continuous operation based on the definition, for purposes of determining the default value, the capacity value of this resource is 40% of its nameplate rating.[3] This method was chosen because PJM could not find a suitable public source of for data regarding a 10-hour continuous battery.

10. I am providing as Appendix A to my affidavit, a worksheet that identifies the applicable reference resource characteristics and shows the installed capital cost ("Capex") and fixed operating and maintenance cost ("FOM") reviewed from different sources of data, the actual values used for each resource in developing the CONE, E&AS revenues, and Net CONE on both a nameplate MW basis and an ICAP MW basis. The worksheet shows the capacity value in percent of the nameplate MW value for solar, wind, and battery energy storage resources used to convert Net CONE from a nameplate basis to an ICAP basis. Also shown in the worksheet are the individual zonal default MOPR Floor Offer Price for each resource type.

[3] Given the pending proceeding on capacity values for Capacity Storage Resources, this value will be updated based on the outcome of those proceedings. *See PJM Interconnection, L.L.C.*, 169 FERC ¶ 61,049 (2019).

Table 1: Illustrative Estimated Average New Entry Default MOPR Floor Offer Prices

Planned Resource Type	Illustrative Default MOPR Floor Offer Prices		
	Gross CONE (Cost of New Entry) $/MW-day (Nameplate)	Estimated Average Zonal E&AS Revenue Offset $/MW-day (Nameplate)	Illustrative MOPR Floor Offer Prices net of E&AS Revenues $/ICAP MW-day
Nuclear	$2,000	$517	$1,483
Coal	$1,068	$43	$1,025
Combined Cycle	$320	$168	$152
Combustion Turbine	$294	$48	$246
Solar PV (Tracking)	$290	$185	$175
Solar PV (Fixed)	$271	$117	$367
Onshore Wind	$420	$240	$1,023
Offshore Wind	$1,155	$337	$3,146
Battery Energy Storage	$532	$116	$1,040
Demand Response (Generation-backed)	$254	$0	$254

The values in Table 1 above are provided for illustration purposes only, as these values are based on an "average Zonal E&AS revenue offset," while the actual Net CONE values used for a given resource will reflect the E&AS revenue offset for the Zone in which that resource resides. The actual zonal Net CONE values proposed by PJM are contained in the accompanying workbook.

11. PJM reviewed cost data sources such as the National Renewable Energy Laboratory ("NREL"), Lazard, U.S. Environmental Protection Agency ("EPA"), and U.S. Energy Information Agency ("EIA"). PJM selected EIA as the primary data source[4] for

4 *See* U.S. Energy Information Administration, *Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating*

all the technologies, except the solar PV (fixed), combustion turbine, combined cycle and demand response resource types. The use of EIA data is appropriate because this data represents the most recent (published in February 2020) publicly available source and is well-documented.[5] Further, the EIA data includes Capex and FOM values for nuclear, coal, solar PV (tracking), onshore wind, offshore wind, and battery energy storage technologies. PJM used EIA's 2019 costs (the most recent cost data available), which were developed based on major categories such as equipment, installation, transmission interconnection, fees, and contingencies. Because the EIA data does not include solar PV (fixed) data, PJM calculated a gross CONE value for that resource type by applying a 0.94 fixed-to-tracking cost ratio to the Capex and FOM values used for solar PV (tracking). This ratio was determined by reviewing publicly available fixed-to-tracking cost ratios from the Lawrence Berkeley National Laboratory's Utility Scale Solar[6] and IHS-Markit's US Solar PV Capital Cost and LCOE Outlook.[4]

12. PJM reviewed and considered data available from NREL, which PJM used to develop values in its October 2018 filing, as the primary data source. However, PJM determined that the EIA data source is superior because it provides greater transparency in the Gross CONE determination. Specifically, values for solar in the NREL reports are listed in direct-current ("DC") terms rather than alternating-current ("AC"). Thus, the use NREL's values would require the use of additional, non-transparent, adjustments to the Capex and FOM costs to convert the measurements to AC. Although the post-adjustment value that would have resulted in roughly the same gross CONE values as the publicly posted EIA data, the use of EIA data avoids the need for the adjustment and maximizes transparency.

13. PJM is using the Gross CONE data for combustion turbine and combined cycle resource types determined by PJM, and approved by the Commission, in the quadrennial review of the Variable Resource Requirement ("VRR") Curve and related inputs in Docket No. ER19-105.[7]

Technologies (February 2020), https://www.eia.gov/analysis/studies/powerplants/capitalcost/ ("EIA Study").

5 In preparing the report for the EIA, Sargent & Lundy "developed the characteristics of the power generating technologies in this study based on information about similar facilities recently built or under development in the United States and abroad," which included "the specification of representative plant sizes, configurations, major equipment, and emission controls." EIA Study at 1.

6 *See* Lawrence Berkeley National Laboratory, *Utility-Scale Solar: Empirical Trends in Project Technology, Cost, Performance, and PPA Pricing in the United States – 2019 Edition* (December 2019), https://emp.lbl.gov/utility-scale-solar/; IHS-Markit Research Services, U.S. Solar PV Capital Cost and LCOE Outlook, https://ihsmarkit.com/research-analysis/index.html.

7 *PJM Interconnection, L.L.C.*, 167 FERC 61,029 (2019).

14. PJM is using Lazard[8] data for the generation-backed demand response resource type. This was the most recent source to include complete cost data for a small (0.5 MW) diesel generator (labeled "Diesel Reciprocating Engine" in Lazard documentation). This size and type of generator, which may be purchased "off-the-shelf," is a good representation of the majority diesel units that are participating as demand response in PJM. The reciprocating internal combustion engine generator type available in the EIA data was approximately 20 MW in size and fired on natural gas, which is a different fuel type than most generators employed for demand response in PJM, and too large for a behind-the-meter installation intended for use to enable demand response and, therefore, is not representative of a generation-backed demand resource in PJM.

15. Utilizing the Capex and FOM data and their identified reference resources, the next step in developing the default MOPR Floor Offer Prices is to determine the Gross CONE. To calculate this, PJM used the pro forma analysis developed by the Brattle Group ("Brattle") in the 2018 quadrennial study of CONE.[9] This analysis determines the nominal levelized annual revenue requirements for a power plant to recover Capex and FOM expenses and earn a return for the investor. The expected life and the financial assumptions used by PJM are the same as those used in the 2018 quadrennial study as shown in Table 2. These assumptions: cost of capital, return on equity, cost of debt and capital structure, as well as annual inflation rate, were found to be just and reasonable by the Commission in its April 2019 Order accepting PJM's quadrennial review filing.[10] Additionally in the Commission's December 19 Order, the Commission found "that default MOPR values should maintain the same basic financial assumptions, such as the 20-year asset life, across resource types" keeping with the Commission's previous determination "that standardized inputs are a simplifying tool appropriate for determining default offer price floors."[11] Finding "that it is reasonable to maintain these basic financial assumptions for default offer price floors in the capacity market to ensure resource offers are evaluated on a comparable basis."[12] However, based on an evaluation of asset life for battery energy storage resources published in several

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[8] *Lazard's Levelized Cost of Energy Analysis–Version 11.0*, Lazard (November 2017), https://www.lazard.com/media/450337/lazard-levelized-cost-of-energy-version-110.pdf ("Lazard Report").

[9] Periodic Review of Variable Resource Requirement Curve Shape and Key Parameters of PJM Interconnection, L.L.C., Docket No. ER19-105-000, at Exhibit No. 2 (2018 CONE Study) (Oct. 10, 2018).

[10] *PJM Interconnection, L.L.C.*, 167 FERC ¶ 61,029, at PP 16, 75-79.

[11] December 19 Order at P 153.

[12] December 19 Order at P 153.

studies (and summarized by NREL[13]), PJM determined that the assumed applicable asset life for battery storage resource should be 15 years.

16. The reference resources are described in Appendix A, where a technology description and an identification of the case number from the EIA report, or other applicable source citation, are provided. As I note above, the reference resources for combined cycle and combustion turbine are those used in the 2018 quadrennial study.

17. To develop the gross CONE values, PJM used 100% Bonus Depreciation for units built to be in service by December 2022 (which declines by 20% every year thereafter) and the following financial assumptions from the 2018 quadrennial review.

Table 2: Financial Assumptions

Financial Assumptions	
Expected Life	20 Years
Debt Ratio	55.0%
Debt Rate	6.0%
Equity Rate	13.0%
Total Tax%	27.7%
ATWAAC	8.2%
Annual Inflation Rate	2.2%

18. PJM added a feature to calculate the Gross CONE value considering the Investment Tax Credit ("ITC") available for solar and wind resources. An ITC up to 30% of the investment is a direct credit against the income tax in the first year. An ITC of 30% approximately reduces CONE value by 30%. PJM assumed that both solar and wind projects qualify for the maximum 30% ITC.

19. Combined cycle and combustion turbine CONE values are the averages of the four CONE areas as determined in the 2018 quadrennial study for 2022/2023.

20. PJM has found its approach for determining the gross CONE values provides a great deal of transparency and is replicable. In fact, any member of the public with access to a pro forma analysis tool can use the Capex and FOM data included in the workbook in Appendix A (which is all from publicly available sources), plus the financial assumptions provided by PJM to reproduce the CONE values PJM calculated.

21. The net energy revenue offset is estimated for each resource class type in each Zone using the average of the annual net energy revenues of the three most recent calendar years preceding the Base Residual Auction where the annual net revenues are calculated using the zonal locational marginal pricing ("LMP") from the relevant zone, as

13 Wesley Cole and A. Will Frazier, Cost Projections for Utility-Scale Battery Storage, National Renewable Energy Laboratory, Figure 7 (June 2019), https://www.nrel.gov/docs/fy19osti/73222.pdf.

described below. Ancillary service revenues are assumed to be $3,350 MW-year (about $9/MW-day)[14] for each resource type except for the combustion turbine for which the ancillary service revenue is assumed to be the $2,199/MW-year (about $6/MW-day) currently prescribed for the Reference Resource combustion turbine in section 5.10(a)(v)(A) of the Tariff, Attachment DD.

- The net energy market revenue offset of the combustion turbine will be estimated using the methodology and all relevant assumptions currently defined in the Tariff. Specifically, PJM will estimate the offset using the methodology defined as the Peak-Hour Dispatch for the Reference Resource combustion turbine, a single 352 MW GE Frame 7HA turbine with a heat rate of 9,134 BTU/MWh and variable operation and maintenance expenses, inclusive of Maintenance Adder costs, of $6.93/MWh.[15]

- The net energy market revenue offset of the combined cycle will be estimated using the methodology currently prescribed in Tariff, Attachment DD, section 5.14(h)(3), except that the heat rate and variable operation and maintenance expenses specified in this section will be revised to be consistent with the 2018 quadrennial review's update of the combined cycle technology to a 1,152 MW 2X1 GE Frame 7HA combined cycle plant with a heat rate of 6,553 BTU/kWh and variable operation and maintenance expenses, inclusive of Maintenance Adder costs, of $2.11 /MWh.

- The net energy market revenue offset of the nuclear resource will be estimated by the gross energy market revenue determined by the product of [average annual zonal day-ahead LMP times 8,760 hours times the annual average equivalent availability factor of all PJM nuclear resources] minus the total annual cost to produce energy determined by the product of [8,760 hours times the annual average equivalent availability factor of all PJM nuclear resources times $9.02/MWh for a single unit plant[16] or $7.66/MWh for a multi-unit plant[17]] where these hourly cost rates include

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14 The $3,350/MW-year ancillary service revenue value is based on information from *State of the Market Report for PJM – Volume 2: Detailed Analysis*, Monitoring Analytics, LLC, Table 7-3 (Mar. 12, 2020), https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2019/2019-som-pjm-volume2.pdf.

15 *See* Tariff, Attachment DD, sections 5.10(v)(A) & (B).

16 *See Gross Avoidable Cost Rates Existing Generation and Net Cost of New Entry for New Energy Efficiency*, The Brattle Group and Sargent & Lundy, at 3-7 (March 17, 2020) ("Brattle Report"). The Brattle Report is included as Exhibit No. 2 to Attachment D to the compliance filing.

17 *See* Brattle Report at 7-10.

fuel costs and variable operation and maintenance expenses, inclusive of Maintenance Adder costs.

- The net energy market revenue of the coal resource will be estimated by a simulated dispatch of a 650 MW coal unit (with heat rate of 8,638 BTU/kWh[18] and variable operations and maintenance variable operation and maintenance expenses, inclusive of Maintenance Adder costs, of $9.50/MWh[19]) using applicable coal prices, as set forth in the PJM Manuals. The unit is committed day-ahead in profitable blocks of at least eight hours, and then committed in real-time for profitable hours if not already committed day ahead;

- The net energy market revenue of the solar PV resource will be estimated using a solar resource model that provides the average MW output level, expressed as a percentage of nameplate rating, by hour of day (for each of the 24-hours of a day) and by calendar month (for each of the 12 months of a year). The annual net energy market revenues are determined by multiplying the solar output level of each hour by the real-time zonal LMP applicable to such hour with this product summed across all of the hours of an annual period. Two separate solar resource models are used, one model for a fixed panel resource and a second model for a tracking panel resource, where the models have been developed using hourly aggregate metered output data of all solar resources of that specific technology type on the PJM system from the calendar years of 2017 through 2019, inclusive.[20] The capacity factor of the solar resource models vary on a monthly basis yielding an annual capacity factor of 13.6% for the fixed panel solar resource and 22.1% for the tracking panel solar resource;

- The net energy market revenue of the onshore wind resource will be estimated using a wind resource model that provides the average MW output level, expressed as a percentage of nameplate rating, by hour of day (for each of the 24-hours of a day) and by calendar month (for each of the 12 months of a year). The annual energy market revenues are determined by multiplying the wind output level of each hour by the real-time zonal LMP applicable to such hour with this product summed across all of the hours of an annual period. The onshore wind resource model has been developed using the hourly aggregate metered output data of all wind resources on the PJM system from the calendar years of 2017 through 2019, inclusive. The capacity factor of the onshore wind resource model varies on a monthly basis yielding an annual capacity factor of 31.2%;

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18 *See* EIA Study at Table 2-1.

19 *See* Brattle report at 10-13.

20 PJM will reevaluate the model as part of the quadrennial review.

- The net energy market revenue of the offshore wind resource will be estimated by the product of [the average annual zonal real-time LMP times 8,760 hours times an assumed annual capacity factor of 45%[21]]; and

- The energy market revenue of the battery energy storage resource will be estimated by a simulated dispatch against historical real-time zonal LMPs where the resource is assumed to be dispatched for the four hours of highest LMP of a daily 24 hour period if the average LMP of these four hours exceeds 120% of the average LMP of the four lowest LMP hours of the same 24 hour period. The net energy market revenues will be determined by the product of [hourly output of 1 MW times the hourly LMP for each hour of assumed discharging] minus the product of [hourly consumption of 1.2 MW times the hourly LMP for each hour of assumed charging] with this net value summed across all of the hours of an annual period. An 83.3% efficiency of the battery energy storage resource is reflected by assuming each 1.0 MW of discharge requires 1.2 MW of charge.

22. PJM's proposed default values are for the 2022/2023 Delivery Year, and therefore must be adjusted to account for inflation and other changes in costs that occur over time. PJM proposes to annually adjust the CONE values of Table 1 by applying a Bureau of Labor and Statistics ("BLS") Composite Index. The same Applicable BLS Composite Index used to adjust the CONE value of the VRR Curve will be applied to the CONE values of the combustion turbine and combine cycle resource types. This BLS composite index is weighted based on 20% Quarterly Census of Employment and Wages for Utility System Construction, 55% Producer Price Index ("PPI") for Construction Materials and Components, and 25% PPI for Turbines and Turbine Generator Sets. For the remaining resource types PJM proposes to use the same categories and weightings, except to replace the Turbines and Turbine Generator Sets with the PPI for Goods Less Food and Energy, Private Capital Equipment.[22][23] The Turbine and Turbine Generator Sets index is applicable to the combustion turbine and combined cycle resource types because they are heavily dependent on that specific technology; however, for the diverse set of resource types listed in Table 1, which employ a wide range of equipment, the broad index of Private Capital Equipment, described below, is more appropriate to capture annual price changes across the industry. The PPI for Private Capital Equipment measures the price change for capital investment in equipment in the final demand

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21 *See Annual Technology Baseline: Electricity – Offshore Wind*, National Renewable Energy Laboratory, https://atb.nrel.gov/electricity/2019/index.html?t=ow&s=ov.

22 *PPI Final Demand and Intermediate Demand (FD-ID) by Commodity Type Aggregation Structure and Definitions*, U.S. Bureau of Labor Statistics, https://www.bls.gov/ppi/fdidbycomtype.htm.

23 *Chapter 14: Producer Prices*, U.S. Bureau of Labor Statistics, https://www.bls.gov/opub/hom/pdf/ppi-20111028.pdf.

portion of the economy. Based on the BLS definition, it contains products that will undergo no further processing and are used to manufacture or transport other goods in the manufacturing sector or are used in the operation of nonmanufacturing industries. Another feature is that "these products are distinguished by the fact that they are amortized over their useful lives and are identified in the I–O tables as Gross Private Fixed Investment." This is indicative of business investment and provides a reasonable measure of major equipment price change from year to year.

23. Consistent with the adjustments to the VRR Curve's CONE value in Tariff, Attachment DD, section 5.10(a)(iv)(B), PJM will then further adjust the default Gross CONE values by a factor of 1.022 for nuclear, coal, combustion turbine, and combine cycle resource types or 1.01 for solar, wind, and storage resource types to reflect the annual decline in bonus depreciation scheduled under federal corporate tax law. The different adjustment factors reflect the different periods over which the tax laws permit the facilities to be depreciated. Nuclear, coal, combustion turbine, and combine cycle resource types are permitted to be depreciated over a period as short as 15 years, while solar, wind, and storage facilities may be depreciated over five years. The accelerated five-year depreciation period results in a quicker recovery of the balance of depreciation not taken in the first year as bonus depreciation and thus a smaller factor.

24. The updated Default MOPR Floor Offer Prices based on updated Net E&AS offset values will be posted 150 days before the applicable RPM Auction.[24]

25. PJM recognizes that the gross CONE values for all resources need to be revisited periodically. Accordingly, PJM will consider such default CONE values as part of the Quadrennial Review that reviews the VRR Curve and CONE estimates once every four years.

26. In addition to the aforementioned Net CONE values, PJM developed default MOPR Floor Offer Prices for new Energy Efficiency Resource Sell Offers into RPM. These values are based on the work done by Brattle and is explained in the Brattle Report included with this filing.[25] The default MOPR Floor Offer Prices for Energy Efficiency Resources is $64/ICAP MW-day.[26] Unlike the other Tariff-stated default values, it is not appropriate to adjust this value before each Base Residual Auction; rather, it should only be adjusted every four years as part of the quadrennial review. The unique nature of Energy Efficiency Resources weighs against such adjustment, as the CONE value is based on an analysis of both costs and savings rather than construction and financing costs like a conventional generator. Further, each Energy Efficiency Resource can only be offered into the capacity market for four consecutive years. After that time, the permanent load reduction provided by the resource is captured in the load forecast.

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24 *See infra* Tables 4 & 5: Illustrative Existing Resource Default Avoidable Cost Rates.

25 Brattle Report at 25-31.

26 *See* Brattle Report at Table 3.

27. 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 the December 2019 Order, the Commission directed PJM to provide a Net CONE for generation-backed Demand Resources based on the underlying technology.[27] In PJM, 86% of the "behind-the-meter" generation participating as generation-backed Demand Resources are diesel-fired reciprocating internal combustion engines.[28] The 2017 Lazard Levelized Cost of Energy Analysis estimates the capital cost of an intermittent operation, 0.5 MW diesel generator at $800/kW and the fixed operations and maintenance costs at $10/kW-yr.[29] Lazard provided two sets of values, one for a unit with a capacity factor of 95%, representative of a resource being used for baseload generation and one for units with a capacity factor of 10%, representative of a resource used to overcome periodic blackouts. The values associated with the unit with a 10% capacity factor were selected for this analysis since it more closely matches the infrequent deployment of demand response in PJM. Utilizing the financial model with the aforementioned financial assumptions, results in a gross cone of $254/MW-day (nameplate). Only 0.2% of Load Management registrations that have a corresponding Economic registration have participated in the energy market for more than 10 hours during 2019. Since this number is so small, the E&AS revenue offset is $0/MW-day, as such the default Net CONE is $254/ICAP MW-day.

28. For Demand Resources that are not generation-backed, as directed by the December 19 Order,[30] PJM will average the Sell Offer prices for Demand Resources with load-backed end-use customer registrations that have been offered in the prior three Base Residual Auctions. PJM will determine the default floor prices for each Locational Deliverability Area ("LDA") based on the MW-weighted average offer price of Demand Resources with load-backed end-use customer registrations. To do so, PJM will determine the MW weighting using the portion of each Demand Resource Sell Offer that is supported by end-use customer locations providing demand response through load reductions, as specified in the registrations provided during the pre-registration process for such Base Residual Auctions and further described in the PJM Manuals. For the 2022/2023 Delivery Year, PJM preliminary determinations for the MOPR Floor Offer Prices, based on the three-year historical average offer prices for Demand Resources, by LDA, are shown in Table 3 below.

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27 December 19 Order at P 144.

28 PJM Demand Side Response Operations, *2019 Distributed Energy Resources (DER) that Participate in PJM Markets as Demand Response*, PJM Interconnection, L.L.C., 5 (February 2020), https://pjm.com/-/media/markets-ops/demand-response/2019-der-annual-report.ashx?la=en.

29 Lazard Report at 7.

30 December 19 Order at P 145.

Table 3: Preliminary Determinations of Load-Backed DR MOPR Floor Offer Prices, By LDA

LDA (Rest Of)	Average
ATSI	$47.07
ATSI-CLEVELAND	$47.54
BGE	$66.81
COMED	$60.55
DAY	$43.20
DEOK	$43.15
DPL-SOUTH	$63.68
EMAAC	$58.18
MAAC	$55.12
PEPCO	$49.56
PPL	$58.57
PSEG	$57.10
PS-NORTH	$52.60
RTO	$49.73
Entire RTO	**$53.32**

Based on these values, the MOPR Floor Offer Price for Planned Demand Resources will range from $43.15.79 to $66.81, depending on the LDA in which the resource resides.

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

29. The default MOPR Floor Offer Price for Sell Offers from existing resources with a State Subsidy will be based on the Net Avoidable Cost Rate ("ACR") values determined for the resource type. Similar to the calculation of the Net CONE, PJM will determine a Gross ACR value that is representative of each resource class and from it will subtract the estimated zonal net E&AS revenues for that asset class, for that Zone. This will result in Net ACR for each asset class, for each Zone in PJM.

30. PJM developed default MOPR Floor Offer Prices for existing resource Sell Offers into RPM using Gross ACR values that are based on the work done by Brattle and is explained in the Brattle Report included with this filing.[31] PJM contracted the Brattle group, along with Sargent & Lundy, to determine the Gross ACRs for the following resource types: nuclear, coal, combined cycle, combustion turbine, solar PV, and onshore wind.[32] Brattle used a bottom up analysis to determine the various costs associated with a "reference plant" of each resource type. Brattle also provided costs associated with "representative-low cost" and "representative-high cost" plants. These costs were then used to estimate the Gross ACRs and variable operations and

31 *See generally* Brattle Report.

32 Brattle Report at 1-2.

maintenance costs. Importantly, Brattle's "cost estimates reflect PJM's market rules concerning the scope of costs that are includable in the Gross ACRs and those that can be included in cost-based energy offers (and thus accounted for in the net E&AS revenue component of Net ACRs)."[33]

31. The analysis provided by the Brattle Report contains a range of values for each Gross ACR for each asset class. This range is provided in Table 4. From the range PJM selected the "Representative Plant" values for use as its Gross ACR value as it is intended to be widely representative of most of the fleet. Additionally, PJM chose this value because it believed that choosing the low end of the range provided by Brattle would result in setting arbitrarily low Net ACRs that would be difficult to defend, and, similarly, choosing the high end would be viewed as overly punitive and would result in more unit-specific analysis of resource costs.

Table 4: Illustrative Existing Resource Default Avoidable Cost Rates

Technology	Representative Low Cost	Representative Plant	Representative High Cost
Single-Unit Nuclear	---	**$697**	---
Multi-Unit Nuclear	$405	**$445**	$457
Coal	$74	**$80**	$166
Gas CC	$55	**$56**	$79
Gas CT	$42	**$50**	$65
Onshore Wind	$76	**$83**	$128
Solar PV	$29	**$40**	$60
Diesel Generator	---	**$3**	---

32. Using the "Representative Plant" values provided in the Brattle Report, PJM calculated Net ACR values shown in Table 5. The estimated average zonal Net E&AS values provided in the table are an RTO-wide average of all zones and therefore do not represent any particular zone. They are provided with the RTO-wide Net ACR values for illustrative purposes only.

33 Brattle report at ii.

Table 5: Illustrative Existing Resource Default Avoidable Cost Rates

Existing Resource Type	Gross ACR ($/MW-day) (Nameplate)	Estimated Average Zonal E&AS Revenue Offset $/MW-day (Nameplate)	Illustrative Net Avoidable Cost Rates in $/ICAP MW-day (Net of E&AS Revenue Offset)
Single-Unit Nuclear	$697	$487	$210
Multi-Unit Nuclear	$445	$517	$0
Coal	$80	$43	$37
Combined Cycle	$56	$168	$0
Combustion Turbine	$50	$48	$2
Solar PV	$40	$185	$0
Solar PV (Fixed)	$40	$117	$0
Onshore Wind	$83	$240	$0
DR Generator	$3	$0	$3
Energy Efficiency	$0	$0	$0

33. PJM proposes to include in the Tariff the Gross ACRs for existing generation resources presented in Table 4, 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 10-year average Handy-Whitman Index in order to account for expected inflation. The adjusted values will be posted on its website 150 days in advance of each Base Residual Auction. The calculation of the estimated zonal net E&AS revenues will be done at the same time prior to each Base Residual Auction and PJM will post the zonal Net ACR values. It is appropriate to use the Handy-Whitman Index for the ACR and not the BLS composite index (as used to adjust annual CONE values) because the BLS composite index includes construction costs which are inapplicable for purposes of calculating going-forward costs. ACR values are only subject to changes such as inflation and equipment costs, not construction costs. Using the Handy-Whitman Index in the calculation of Gross ACR used in the default MOPR Floor Offer Price is also consistent with the use of the Handy-Whitman Index in the calculation of the resource-specific ACR offer cap calculation.[34]

34. As directed by the December 19 Order,[35] PJM determined default net E&AS revenues for each resource type on a Zonal basis and will net those values against the gross ACRs to determine the default MOPR Floor Offer Prices for Cleared Capacity Resources with State Subsidy.

35. For load-backed Existing Demand Resources and Energy Efficiency, PJM was unable to determine any material avoidable costs associated with these resource

[34] *See* Tariff, Attachment DD, section 6.8(a) (Adjustment Factor).

[35] December 19 Order at P 154.

types. Costs associated with load-backed Demand Resources and Energy Efficiency typically include up front metering, equipment, and software installations and process changes that are applicable to planned resources of these types only. This electrical equipment is purchased for specific function such as cooling, lighting or building a product. PJM is not aware of any material avoidable costs to carry forward the load reduction capability on an Existing Demand Resource or an existing Energy Efficiency Resource for electrical equipment purchased once the initial investment has been made. Given this, and the difficulty in implementing a resource-specific process for load-backed Existing Demand Resources and existing Energy Efficiency Resources, it is appropriate to provide in the Tariff that the MOPR Floor Offer Prices for existing Demand Resources and Energy Efficiency are zero dollars.

36. In conclusion, I would like to clarify that while the Net CONE and Net ACR values determined by PJM are supported by the calculations laid out within the Tariff, publicly available data, and expert analysis from the Brattle Group and Sargent and Lundy, they are based on industry average data used in a manner that is intended to calculate a reasonable, average floor offer price for a resource of a specific class in a specific location. As such, Capex, FOM and the relevant financing assumptions may differ across new projects as may the actual fixed costs of an existing resource used to determine the Gross ACR. Specifically, parameters such as the Capacity Performance Quantifiable Risk ("CPQR") adder are set to $0/MW-day in these calculations which is consistent with defining an offer floor. Finally, the determination of net E&AS revenues used in the calculation of the default MOPR Floor Offer Prices is consistent with the process described in the December 19 Order which is to use average zonal historic net E&AS revenues. This method may not reflect the expectations of all sellers as some may elect to estimate revenues on a forward-looking basis rather than historic. These deviations from the assumptions used to calculate the default MOPR Floor Offer Prices are entirely reasonable and illustrate the difficulty in coming up with singular default values. However, they also illustrate the importance of the flexibility afforded through the resource-specific process.

37. 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)

VERIFICATION OF ADAM J. KEECH

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

Subscribed and sworn to before me, the undersigned notary public, this 17 day of March 2020.

Linda Spreeman
Notary Public

Commonwealth of Pennsylvania - Notary Seal
Linda Spreeman, Notary Public
Montgomery County
My commission expires November 17, 2023
Commission number 1158343
Member, Pennsylvania Association of Notaries

Default MOPR Floor Offer Prices Workbook Index (3/18/2020)

Default Net CONE

Default Net CONE Summary	Resource Installed Capital and Fixed O&M costs, Gross CONE, Net Energy & Ancillary Services Revenue Offset, Net CONE in terms of nameplate MW , and Default Net CONE in $/ICAP MW-Day
Default Zonal Net CONE	Zonal Net Energy & Ancillary Services Revenue Offset and Zonal Net CONE
CONE Reference Resources	Brief description, EIA case number, Fixed O&M and Capital Cost of Reference Resources
CONE Capital Cost Sources	Links to sources of capital cost data
CONE Capital Cost Comparison	Comparison of capital costs from selected sources
CONE Financial Parameters	Financial parameters used in CONE calculation from installed capital and Fixed O&M costs

Default Net ACR

Default Net ACR Summary	Resource Gross ACR, Average Net Energy & Ancillary Services Revenue Offset, Net ACR, Default Net ACR
Default Zonal Net ACR	Zonal Net Energy & Ancillary Services Revenue Offset, Zonal Net ACR, and Default Net ACR

Default Net CONE

Resource Type	Fixed O&M Cost ($/kW - year)	Installed Capital Cost, ($/kW)	Investment Tax Credit %	Gross CONE ($/MW-Day) (Nameplate)	Average Zonal Net Energy Revenue Offset ($/MW-Day) (Nameplate)	Average Zonal Net Ancillary Services Revenue Offset ($/MW-Day) (Nameplate)	Net CONE ($/MW-Day) (Nameplate)	Capacity Value (% Nameplate MW)	Net CONE ($/ICAP-MW-Day)
Nuclear	$122	$6,041	NA	$2,000	$508	$9	$1,483		$1,483
Coal	$41	$3,676	NA	$1,068	$34	$9	$1,025		$1,025
Combined Cycle			NA	$320	$159	$9	$152		$152
Combustion Turbine			NA	$294	$42	$6	$246		$246
Solar PV (Tracking)	$15	$1,313	30%	$290	$176	$9	$105	60.0%	$175
Solar PV (Fixed)	$14	$1,234	30%	$271	$108	$9	$154	42.0%	$367
Onshore Wind	$35	$1,677	30%	$420	$231	$9	$180	17.6%	$1,023
Offshore Wind	$110	$4,375	30%	$1,155	$328	$9	$818	26.0%	$3,146
Battery Energy Storage	$25	$1,389	NA	$532	$107	$9	$416	40.0%	$1,040
Demand Response (Gen)	$10	$800	NA	$254	$0	$0	$254		$254

Notes:

Fixed O&M and installed capital costs are from EIA report 2020. Solar PV (fixed) costs are 94% of the costs for Solar PV (Tracking). Nuclear and Coal Fixed O&M costs were reduced by $20 and $25 respectively in calculating Gross CONE.

Combined Cycle and Combustion Turbine CONE values are average of CONE Area values from 2018 Quadrennial Study for 2022.

Solar and Wind Investment Tax Credit depends on start of the construction. An optimistic 30% value is assumed implying Solar construction started before 1/1/2020 and Wind construction started before 1/1/2017.

Class average capacity values as percent of nameplate MW Solar and Wind generation are used to calculate Net CONE in $/ICAP-MW-Day.

Battery energy storage costs are for a 4 hour plant with 15 year life. Gross CONE is calculated based on 15 year economic life and a 40% capacity value as percent of nameplate capacity is used to calculate Net CONE in $/ICAP-MW-Day.

Net Energy Revenue Offset is based on methodologies described in posted 3/11/2020 MIC material and Ancillary Service revenue Offset is based on reactive services of $3350/MW-year or $9/MW-day. The CT value is from the tariff: $2199/MW-year of $6/MW-day.

Solar PV (Tracking)			
		Gross CONE	$290
		Net Ancillary Revenue Offset	$9
		Capacity Value (% Nameplate MW)	60%
Zone	**Net Energy Revenue Offset**	**Net CONE**	**Default Net CONE ($/ICAP MW-Day)**
AECO	$158	$123	$205
AEP	$181	$100	$167
APS	$182	$99	$165
ATSI	$191	$90	$150
BGE	$200	$81	$135
COMED	$161	$120	$200
DAYTON	$190	$91	$152
DEOK	$188	$93	$155
DOM	$191	$90	$150
DPL	$173	$108	$180
DUQ	$189	$92	$153
EKPC	$173	$108	$180
JCPL	$160	$121	$202
METED	$167	$114	$190
PECO	$157	$124	$207
PENELEC	$175	$106	$177
PEPCO	$193	$88	$147
PPL	$158	$123	$205
PSEG	$162	$119	$198
RECO	$166	$115	$192
Average	**$176**	**$105**	**$175**

Solar PV (Fixed)			
		Gross CONE	$271
		Net Ancillary Revenue Offset	$9
		Capacity Value (% Nameplate MW)	42%
Zone	**Net Energy Revenue Offset**	**Net CONE**	**Default Net CONE ($/ICAP MW-Day)**
AECO	$96	$166	$395
AEP	$111	$151	$360
APS	$112	$150	$357
ATSI	$117	$145	$345
BGE	$122	$140	$333
COMED	$99	$163	$388
DAYTON	$117	$145	$345
DEOK	$116	$146	$348
DOM	$117	$145	$345
DPL	$105	$157	$374
DUQ	$116	$146	$348
EKPC	$106	$156	$371
JCPL	$98	$164	$390
METED	$102	$160	$381
PECO	$96	$166	$395
PENELEC	$107	$155	$369
PEPCO	$118	$144	$343
PPL	$97	$165	$393
PSEG	$99	$163	$388
RECO	$101	$161	$383
Average	**$108**	**$154**	**$367**

Onshore Wind			
		Gross CONE	$420
		Net Ancillary Revenue Offset	$9
		Capacity Value (% Nameplate MW)	17.6%
Zone	**Net Energy Revenue Offset**	**Net CONE**	**Default Net CONE ($/ICAP MW-Day)**
AECO	$223	$188	$1,068
AEP	$230	$181	$1,028
APS	$236	$175	$994
ATSI	$237	$174	$989
BGE	$258	$153	$869
COMED	$197	$214	$1,216
DAYTON	$235	$176	$1,000
DEOK	$231	$180	$1,023
DOM	$249	$162	$920
DPL	$243	$168	$955
DUQ	$234	$177	$1,006
EKPC	$219	$192	$1,091
JCPL	$224	$187	$1,063
METED	$226	$185	$1,051
PECO	$219	$192	$1,091
PENELEC	$229	$182	$1,034
PEPCO	$251	$160	$909
PPL	$218	$193	$1,097
PSEG	$227	$184	$1,045
RECO	$228	$183	$1,040
Average	**$231**	**$180**	**$1,023**

Offshore Wind			
		Gross CONE	$1,155
		Net Ancillary Revenue Offset	$9
		Capacity Value (% Nameplate MW)	26.0%
Zone	**Net Energy Revenue Offset**	**Net CONE**	**Default Net CONE ($/ICAP MW-Day)**
AECO	312	$834	$3,208
AEP	329	$817	$3,141
APS	336	$810	$3,116
ATSI	341	$805	$3,097
BGE	366	$780	$2,999
COMED	286	$860	$3,307
DAYTON	339	$807	$3,103
DEOK	333	$813	$3,126
DOM	353	$793	$3,049
DPL	342	$804	$3,092
DUQ	336	$810	$3,115
EKPC	316	$830	$3,194
JCPL	313	$833	$3,204
METED	318	$828	$3,184
PECO	307	$839	$3,227
PENELEC	325	$821	$3,157
PEPCO	356	$790	$3,038
PPL	306	$840	$3,232
PSEG	317	$829	$3,190
RECO	320	$826	$3,178
Average	**$328**	**$818**	**$3,146**

Battery Energy Storage			
		Gross CONE	$532
		Net Ancillary Revenue Offset	$9
		Capacity Value (% Nameplate MW)	40.0%
Zone	**Net Energy Revenue Offset**	**Net CONE**	**Default Net CONE ($/ICAP MW-Day)**
AECO	93	$430	$1,076
AEP	103	$420	$1,050
APS	106	$417	$1,042
ATSI	114	$409	$1,023
BGE	132	$391	$977
COMED	97	$426	$1,064
DAYTON	112	$411	$1,028
DEOK	117	$406	$1,015
DOM	122	$401	$1,002
DPL	125	$398	$994
DUQ	115	$408	$1,021
EKPC	98	$425	$1,062
JCPL	93	$430	$1,076
METED	106	$417	$1,044
PECO	89	$434	$1,085
PENELEC	100	$423	$1,057
PEPCO	123	$400	$1,001
PPL	94	$429	$1,073
PSEG	96	$427	$1,068
RECO	101	$422	$1,055
Average	**$107**	**$416**	**$1,040**

Descriptions and Costs of Reference Resources

Resource Type	Technology Description	Source of Information	Fixed O&M ($/kW-year)	Installed Capital Cost ($/kW)
Nuclear	2 x Westinghouse AP1000 Pressurized Water Reactor (2,156 MW)	EIA (Case 11)	122	6,041
Coal	Ultra-Super Critical Coal (650 MW)	EIA (Case 1)	41	3,676
Combined Cycle	2x1 GE Frame 7HA with evaporative cooling and SCR (1,152 MW)	Quadrennial Review	24	874
Combustion Turbine	GE Frame 7HA CT with evaporative cooling, SCR, dual fuel (352 MW)	Quadrennial Review	17	875
Solar PV - Tracking	Single-axis tracking (150 MW AC)	EIA (Case 24)	15	1,313
Solar PV - Fixed	Fixed-tilt (100 MW AC)	EIA, LBNL, IHS	14	1,234
Onshore Wind	17 x 2.8 MW WTGs (50 MW)	EIA (Case 21)	35	1,677
Offshore Wind	40 x 10 WTGs, 100’ depth (400 MW)	EIA (Case 22)	110	4,375
Battery Storage	50 MW utility scale, Li, 200 MWh rating	EIA (Case 18)	25	1,389
Demand Response	0.5 MW RICE, diesel, 10,000 Btu/kWh	Lazard LCOE V-11.0	10	800

Sources of Technology Costs

Source	Link
NREL: 2019 Annual Technology Baseline	atb.nrel.gov
Lazard: 2019 Levelized Cost of Energy & Storage	https://www.lazard.com/perspective/lcoe2019
	https://www.lazard.com/media/451087/lazards-levelized-cost-of-storage-version-50-vf.pdf
	https://www.lazard.com/media/451086/lazards-levelized-cost-of-energy-version-130-vf.pdf
Lazard: 2017 Levelized Cost of Energy & Storage	https://www.lazard.com/perspective/levelized-cost-of-energy-2017/
EPA: IPM Platform 2018 Reference Case	https://www.epa.gov/airmarkets/documentation-ipm-platform-v6-november-2018-reference-case-all-chapters
EIA: 2020 Capital Cost Report	https://www.eia.gov/analysis/studies/powerplants/capitalcost/
PJM: Quadrennial Review	https://pjm.com/-/media/library/reports-notices/special-reports/2018/20180420-pjm-2018-cost-of-new-entry-study.ashx?la=en
LBNL: Utility Scale Solar – 2019 Edition	https://emp.lbl.gov/utility-scale-solar/
IHS: US Solar PV Capital Cost and LCOE Outlook	https://ihsmarkit.com/research-analysis/index.html

Comparison of Installed Capital Costs ($/kW)

Technology	NREL 2022	Lazard 2019	EPA 2021	EIA 2019	Used by PJM
Nuclear	6,506	6,900 – 12,200	5,644	6,041	6,041
Coal	3,944	3,000 – 6,250	3,580	3,676	3,676
Combined Cycle	894	700 – 1,300	1,081	1,084 (H)	874
Combustion Turbine	905	700 – 950	662	713 (7FA)	875
Solar PV (tracking)	1343*	1,100	1,034	1,313	1,313
Solar PV (fixed)	1,262**	900		1,234**	1,234
Onshore Wind	1,472	1,100 – 1,500	1,404	1,677	1,677
Offshore Wind	3,682	2,350 – 3,550	4,529	4,375	4,375
Battery Storage	1,157	898 – 1,874	N/A	1,389	1,389

** NREL installed capital cost is noted as $1033/kW DC and PJM multiplied the value by an Inverter Loading Ratio of 1.3 to calculate $1343/kW AC.*

*** Fixed cost obtained from multiplying Tracking cost by 0.94*

Financial Parameters

Financial Assumptions	
Expected Life	20 Years
Debt Ratio	55.0%
Debt Rate	6.0%
Equity Rate	13.0%
Total Tax Rate	27.70%
ATWACC	8.2%
Inflation Rate	2.2%

Financial assumptions developed during 2018 Quadrennial Review were used to determine Gross CONE from the installed capital and fixed O&M costs.

Default Gross and Net ACR

Resource Type	Gross ACR ($/MW-Day) (Nameplate)	Average Zonal Net Energy Revenue Offset ($/MW-Day) (Nameplate)	Average Zonal Net Ancillary Services Revenue Offset ($/MW-Day) (Nameplate)	Net ACR ($/MW-Day) (Nameplate)	Effective Net ACR ($/MW-Day) (Nameplate)	Capacity Value (% Nameplate MW)	Default Net ACR ($/ICAP-MW-Day)
Single-Unit Nuclear	$697	$478	$9	$210	$210		$210
Multi-Unit Nuclear	$445	$508	$9	-$72	$0		$0
Coal	$80	$34	$9	$37	$37		$37
Combined Cycle	$56	$159	$9	-$112	$0		$0
Combustion Turbine	$50	$42	$6	$2	$2		$2
Solar PV (Tracking)	$40	$176	$9	-$145	$0	60.0%	$0
Solar PV (Fixed)	$40	$108	$9	-$77	$0	42.0%	$0
Onshore Wind	$83	$231	$9	-$157	$0	17.6%	$0
Diesel Generator (DR)	$3	$0	$0	$3	$3		$3
Energy Efficiency	$0	$0	$0	$0	$0		$0

Solar PV (Tracking)			
		Gross ACR	$40
		Net Ancillary Revenue Offset	$9
		Capacity Value (% Nameplate MW)	60%
Zone	**Net Energy Revenue Offset**	**Net ACR**	**Default Net ACR ($/ICAP MW-Day)**
AECO	$158	($127)	$0
AEP	$181	($150)	$0
APS	$182	($151)	$0
ATSI	$191	($160)	$0
BGE	$200	($169)	$0
COMED	$161	($130)	$0
DAYTON	$190	($159)	$0
DEOK	$188	($157)	$0
DOM	$191	($160)	$0
DPL	$173	($142)	$0
DUQ	$189	($158)	$0
EKPC	$173	($142)	$0
JCPL	$160	($129)	$0
METED	$167	($136)	$0
PECO	$157	($126)	$0
PENELEC	$175	($144)	$0
PEPCO	$193	($162)	$0
PPL	$158	($127)	$0
PSEG	$162	($131)	$0
RECO	$166	($135)	$0
Average	**$176**	**($145)**	**$0**

Solar PV (Fixed)			
		Gross ACR	$40
		Net Ancillary Revenue Offset	$9
		Capacity Value (% Nameplate MW)	42%
Zone	**Net Energy Revenue Offset**	**Net ACR**	**Default Net ACR ($/ICAP MW-Day)**
AECO	$96	($65)	$0
AEP	$111	($80)	$0
APS	$112	($81)	$0
ATSI	$117	($86)	$0
BGE	$122	($91)	$0
COMED	$99	($68)	$0
DAYTON	$117	($86)	$0
DEOK	$116	($85)	$0
DOM	$117	($86)	$0
DPL	$105	($74)	$0
DUQ	$116	($85)	$0
EKPC	$106	($75)	$0
JCPL	$98	($67)	$0
METED	$102	($71)	$0
PECO	$96	($65)	$0
PENELEC	$107	($76)	$0
PEPCO	$118	($87)	$0
PPL	$97	($66)	$0
PSEG	$99	($68)	$0
RECO	$101	($70)	$0
Average	**$108**	**($77)**	**$0**

Onshore Wind			
		Gross ACR	$83
		Net Ancillary Revenue Offset	$9
		Capacity Value (% Nameplate MW)	17.6%
Zone	**Net Energy Revenue Offset**	**Net ACR**	**Default Net ACR ($/ICAP MW-Day)**
AECO	$223	($149)	$0
AEP	$230	($156)	$0
APS	$236	($162)	$0
ATSI	$237	($163)	$0
BGE	$258	($184)	$0
COMED	$197	($123)	$0
DAYTON	$235	($161)	$0
DEOK	$231	($157)	$0
DOM	$249	($175)	$0
DPL	$243	($169)	$0
DUQ	$234	($160)	$0
EKPC	$219	($145)	$0
JCPL	$224	($150)	$0
METED	$226	($152)	$0
PECO	$219	($145)	$0
PENELEC	$229	($155)	$0
PEPCO	$251	($177)	$0
PPL	$218	($144)	$0
PSEG	$227	($153)	$0
RECO	$228	($154)	$0
Average	**$231**	**($157)**	**$0**

Diesel Generator (DR)			
		Gross ACR	$3
		Net Ancillary Revenue Offset	$0
		Capacity Value (% Nameplate MW)	NA
Zone	**Net Energy Revenue Offset**	**Net ACR**	**Default Net ACR ($/ICAP MW-Day)**
AECO	0	$3	$3
AEP	0	$3	$3
APS	0	$3	$3
ATSI	0	$3	$3
BGE	0	$3	$3
COMED	0	$3	$3
DAYTON	0	$3	$3
DEOK	0	$3	$3
DOM	0	$3	$3
DPL	0	$3	$3
DUQ	0	$3	$3
EKPC	0	$3	$3
JCPL	0	$3	$3
METED	0	$3	$3
PECO	0	$3	$3
PENELEC	0	$3	$3
PEPCO	0	$3	$3
PPL	0	$3	$3
PSEG	0	$3	$3
RECO	0	$3	$3
Average	**$0**	**$3**	**$3**