UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	**)**	**Docket No. ER24-___-000**

Proposed Enhancements to PJM's Capacity Market Rules - Market Seller Offer Cap, Performance Payment Eligibility, and Forward Energy and Ancillary Service Revenues

Craig Glazer
Vice President–Federal Government Policy
PJM Interconnection, L.L.C.
1200 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 423-4743 (phone)
(202) 393-7741 (fax)
Craig.Glazer@pjm.com

Chenchao Lu
Associate General Counsel
PJM Interconnection, L.L.C.
2750 Monroe Blvd.
Audubon, PA 19403
(610) 666-2255 (phone)
(610) 666-8211 (fax)
Chenchao.Lu@pjm.com

October 13, 2023

TABLE OF CONTENTS

PJM Interconnection, L.L.C.
2750 Monroe Blvd.
Audubon, PA 19403-2497

Chenchao Lu
Associate General Counsel
T: 610.666.2255 | F: 610.666.8211
Chenchao.Lu@pjm.com

October 13, 2023

Via Electronic Filing

Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426-0001

Re: PJM Interconnection, L.L.C., Docket No. ER24-___-000
Proposed Enhancements to PJM's Capacity Market Rules - Market Seller Offer Cap, Performance Payment Eligibility, and Forward Energy and Ancillary Service Revenues

Dear Secretary Bose:

Pursuant to section 205 of the Federal Power Act, 16 U.S.C. § 824d, and the Federal Energy Regulatory Commission's ("Commission" or "FERC") Regulations,[1] PJM Interconnection, L.L.C. ("PJM") hereby submits proposed revisions to the PJM Open Access Transmission Tariff ("Tariff") and the Reliability Assurance Agreement ("RAA"). Specifically, as further explained below, PJM proposes revisions in this filing to enhance the rules governing the Market Seller Offer Cap[2] by (1) establishing a standardized methodology that can be used to calculate a unit-specific Capacity Performance Quantifiable Risk,[3] (2) allowing Capacity Market Sellers of resources that will participate in the energy and ancillary service markets, regardless of receiving a capacity commitment,

---

[1] 18 C.F.R. part 35.

[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.

[3] As used in this filling, this term refers to the cost of risk as further described in Tariff, Attachment DD, section 6.8.

to reflect their respective cost of risk associated with capacity performance in their capacity market offers, (3) allowing segmented unit-specific offer caps, (4) better aligning the Market Seller Offer Cap rules that may be applied to Planned Generation Capacity Resources with costs they may incur, and (5) providing more flexibility for PJM in approving a unit-specific Market Seller Offer Cap. In addition to these revisions, PJM also proposes in this filing to enhance certain rules related to capacity performance by (1) aligning the eligibility of Performance Payments during Performance Assessment Intervals to committed Capacity Resources, (2) clarifying when committed Capacity Resources are excused from Non-Performance Charges, (3) excluding any excused resources from the dominator of the Balancing Ratio, (4) establishing the ability for Market Participants to transfer performance obligations of Capacity Resources before a Performance Assessment Interval, and (5) removing the physical option for FRR Entities that underperform during a Performance Assessment Interval. Finally, through this filing, PJM is also adopting a forward looking Energy and Ancillary Service ("EAS") offset for purposes of calculating the Market Seller Offer Cap and Minimum Offer Price Rule ("MOPR").

This set of proposed revisions complements the enhancements to risk modeling, resource accreditation (including associated alignment to resources allowed in the Fixed Resource Requirement ("FRR")), stop-loss, and testing being proposed in a concurrent but separate filing. The combination of these two filings represent a comprehensive set of reforms that will help to maintain resource adequacy in the PJM Region through a competitive capacity market construct. To that end, PJM urges that the Commission accept both filings concurrently within the requested timeframe so that the reforms set forth in this filing align with the changes proposed in PJM's separate filing on risk modeling, accreditation, stop-loss, and testing.

To be clear, PJM's proposed revisions in this proceeding are just and reasonable on a standalone basis, as explained and supported by this transmittal and the attached affidavits. Likewise, PJM's proposed revisions in the concurrent filing are also just and reasonable on a standalone basis. However, the combined revisions contained within the two section 205 filings together would provide greater synergies and is preferable as a just and reasonable capacity construct for the PJM Region. Indeed, acceptance of both filings will appropriately reflect the synergies between compensation for risk and bonus eligibility with the new testing requirements and accreditation rules that will apply to Capacity Resources that are committed in the capacity market. In addition, acceptance of both files concurrently and without delay will allow these enhancements to be implemented with the upcoming Base Residual Auction associated with the 2025/2026 Delivery Year.

While PJM has outlined the ties between the two filings, PJM is submitting these as separate section 205 filings for ease of processing given the reality that there is currently less than one year between the already delayed 2025/2026 Base Residual Auction and the actual Delivery Year itself. Delaying acceptance of either one of these proposals beyond the requested 60-day timeframe would shorten the amount of time that Market Participants, PJM, and the Market Monitor have to prepare for the next Base Residual Auction and likely require PJM to (1) initiate the pre-auction activities on a parallel path (one under the existing rules and another under the proposed rules) or (2) proceed with the upcoming Base Residual Auction without the proposed enhancements that are the subject of a delayed Commission order.

Because neither is an optimal outcome and in light of limitations the Commission may otherwise face under the *NRG* precedent if these were combined into a single filing,[4] PJM is submitting the components within this filing as a separate section 205 proceeding from the enhancements related to resource accreditation, risk modeling, testing requirements, and stop-loss that PJM is proposing in the separate section 205 filing. In this way, should the Commission deem that additional information is necessary in one of these proceedings, it does not need to delay acceptance of the other enhancements in the separate filing.

Unique to this section 205 filing, to provide further flexibility for the Commission, PJM also consents to make the proposed revision regarding the eligibility of Performance Payments and associated Balancing Ratio update detailed in section II(D) of this filing severable from the remainder of the proposals specified in this filing.[5] Only the proposed changes to Performance Payment eligibility are severable from the remaining items in this filing. In other words, PJM's consent to sever does not extend to splitting out any of the remaining proposals in this filing letter.[6] To be clear, PJM strongly urges the Commission to accept this filing in its entirety without modification and PJM's consent is limited only to the Commission severing the bonus eligibility proposal and associated Balancing Ratio update specified in section II(C) of this filing to the extent necessary.

---

[4] *See NRG Power Mktg., LLC v. FERC*, 862 F.3d 108, 114-15 (D.C. Cir. 2017).

[5] To clarify, PJM's proposal to exclude from the Balancing Ratio calculation for resources that are excused from Non-Performance Charges, as detailed in section II(A), is not part of this severability.

[6] PJM further clarifies that although it is severing these issues for purposes of the application of the *NRG* precedent, PJM is not waiving its rights under Section 205 to receive a ruling on this severed issue within 60 days from this filing.

This filing represents the product of a robust stakeholder process that began nearly two years ago through the Resource Adequacy Senior Task Force ("RASTF")[7] and continued through the Board initiated Critical Issue Fast Path ("CIFP") on resource adequacy.[8] Specifically, the CIFP process which culminated with this filing contained 17 total meetings (16 substantive meetings and one stakeholder review of the governing document changes). That set of stakeholder meetings was preceded by 30 meetings of the RASTF stakeholder group between October 2021 and March 2023. In total, there have been 47 stakeholder meetings since October 2021 to explore reforms to the capacity market. This process included oral and written presentations directly to the PJM Board on each of these issues. Based on the extensive stakeholder feedback and input, the PJM Board ultimately directed PJM to file the proposed changes described in this filing, which PJM fully supports, along with the additional enhancements to the capacity market rules in the separate companion filing, and notified stakeholders of this decision in a letter on September 27, 2023.[9] PJM requests that the Commission issue its order accepting the enclosed revisions by no later than December 12, 2023, 60 days from the date of this filing, with an effective date of December 12, 2023, for all revisions contained herein.

---

[7] *See* Resource Adequacy Senior Task Force, *Agenda*, PJM Interconnection, L.L.C. (Oct. 22, 2021), https://www.pjm.com/-/media/committees-groups/task-forces/rastf/2021/20211022/20211022-agenda.ashx.

[8] *See* Letter from Mark Takahashi, Chair, PJM Board of Managers, to PJM Interconnection, L.L.C. Stakeholders (Feb. 24, 2023) (https://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/20230224-board-letter-re-initiation-of-the-critical-issue-fast-path-process-to-address-resource-adequacy-issues.ashx) (initiating the Critical Issue Fast Path).

[9] *See* Letter from Mark Takahashi, Chair, PJM Board of Managers, to PJM Interconnection, L.L.C. Stakeholders (Sept. 27, 2023) (https://pjm.com/-/media/about-pjm/who-we-are/public-disclosures/20230927-pjm-board-letter-re-its-decision-within-the-cifp-ra.ashx).

I. ENHANCEMENTS TO THE MARKET SELLER OFFER CAP WILL IMPROVE THE ABILITY OF THE CAPACITY MARKET TO PRODUCE COMPETITIVE OUTCOMES

The Market Seller Offer Cap is one tool used to mitigate against seller-side market power in PJM's capacity market. To protect against the potential exercise of market power through economic withholding of existing resources by capacity suppliers, PJM's Market Seller Offer Cap rules set a ceiling on the Sell Offers that may be submitted by Capacity Market Sellers who fail PJM's market power test.[10] By capping capacity offers from such Capacity Market Sellers, the Market Seller Offer Cap rule is intended to prevent those that may have the ability to exercise market power from inappropriately raising the overall capacity market clearing prices. PJM's capacity market also requires certain Existing Generation Capacity Resources be offered into each RPM Auction as an additional component of the market power mitigation framework.[11] This requirement, commonly referred to as the must offer rule, supplements the Market Seller Offer Cap provisions by preventing Capacity Market Sellers from withholding resources that are offered in the capacity market. The combination of these market mitigation rules are intended to ensure competitive market outcomes by preventing the exercise of market power.

Dr. Walter Graf, Chief Economist at PJM, explains that "[t]he fundamental objective of market power mitigation in the capacity market is to return the capacity market to outcomes that would prevail in a competitive market: one with prices reflecting marginal

---

[10] *See PJM Interconnection, L.L.C.*, 154 FERC ¶ 61,151, at P 52 (2016) ("Market power mitigation in the [PJM] capacity market entails limiting the capacity offers of all existing capacity resources to either the default or unit-specific value to prevent economic withholding that could otherwise result in market clearing capacity prices exceeding a competitive level.").

[11] *See* Tariff, Attachment DD, section 6.6.

value and the marginal economic costs of competitive market participants. Accomplishing this objective requires mitigation of uncompetitive offers to competitive levels."[12] The competitive offer level for each Capacity Resource is the expected profit-maximizing offer of a competitive participant, which is "equal to their economic costs of offering the resource into the capacity market, accepting the capacity commitment, and complying with all relevant obligations of a Capacity Resource."[13] As Dr. Graf further explains, "the relevant costs that a competitive Capacity Market Seller would wish to represent in a capacity offer are any and all costs that have not yet been incurred and could be avoided by not selling capacity, net of any revenues that are enabled by the Capacity Market Seller choosing to incur the costs."

A. *PJM Proposes to Clarify Tariff Provisions Regarding the Capacity Performance Quantifiable Risk Component.*

In the capacity performance order,[14] the Commission explained that the Avoidable Cost Rate ("ACR") "reflect the cost of becoming a capacity resource . . . and that, for some resources, the overall physical and capital expenditures required to ensure performance during emergency operations are extensive, presenting additional costs which are not currently reflected in the Avoidable Cost Rate calculation."[15] Thus, the Commission noted that "Capacity Performance Quantifiable Risk is intended to explicitly allow suppliers to include in their offers risks that can be quantified and that are not already reflected in the

---

[12] Affidavit of Walter Graf on Behalf of PJM Interconnection, L.L.C. ("Graf Aff.") ¶ 76.

[13] Graf Aff. ¶ 77.

[14] *PJM Interconnection, L.L.C.*, 151 FERC ¶ 61,208 (2015), *order on reh'g & compliance*, 155 FERC ¶ 61,157 (2016), *aff'd sub nom. Advanced Energy Mgmt. All. v. FERC*, 860 F.3d 656 (D.C. Cir. 2017).

[15] *PJM Interconnection, L.L.C.*, 151 FERC ¶ 61,208, at P 353.

[ACR] formula."[16] The Commission has since reaffirmed that "the replacement rate continues to provide capacity sellers a full opportunity to include appropriate costs and risks in their offers."[17] More particularly, the Commission explained that in developing the Market Seller Offer Cap, Capacity Market Sellers may "include costs and risk assessments that are quantifiable, reasonably supported, and attributable to a seller's capacity obligation under Capacity Performance. The unit-specific mitigation structure does not supplant any seller's ability to formulate those costs in the first instance . . . ."[18] The Commission further explained that "any cost or risk that can be adequately supported by a seller as arising from its need to meet a capacity supply obligation, and is allowable under the Tariff, is acceptable in unit-specific review."[19]

In sum, the Commission has clearly indicated that Capacity Market Sellers should be allowed to include the cost of the risk of Non-Performance Charges that a committed Capacity Resource may incur during a Performance Assessment Interval as part of the unit-specific Market Seller Offer Cap calculation. This cost of risk is allowable under the Capacity Performance Quantifiable Risk ("CPQR"), "which may include sellers' quantifiable, reasonably-supported risks attributable to a Capacity Performance obligation."[20]

---

[16] *Id*.

[17] *Indep. Market Monitor for PJM v. PJM Interconnection, L.L.C.*, 176 FERC ¶ 61,137 (2021), *order on reh'g,* 178 FERC ¶ 61,121, at P 16 (2022), *aff'd sub nom. Vistra Corp. v. FERC*, 80 F.4th 302 (D.C. Cir. 2023).

[18] *Id.*

[19] *Id.* at P 86.

[20] *Id*. at P 47.

Despite the Commission's assurances regarding the inclusion of CPQR in a Capacity Market Seller's offer, the lack of clarity on CPQR in the Tariff has led to this issue becoming unduly contentious in the unit-specific review process and have limited the ability of Capacity Market Sellers to reflect CPQR risk in their offers due to this lack of clarity.[21] Additionally, as further discussed below, Capacity Market Sellers of certain resources have no ability to reflect CPQR in their offer because of deficiencies in the current calculation of the net ACR. This can result in certain Capacity Market Sellers of certain Capacity Resources that are subject to the must offer requirement to offer at $0.00/MW-day, which essentially requires Capacity Market Sellers to take on a capacity commitment at a potentially uneconomic level, despite the known risk of incurring Non-Performance Charges. To address these issues, this filing proposes enhancements to the unit-specific Market Seller Offer Cap rules so that Capacity Market Sellers can, in all cases, adequately reflect the cost of risk associated with committing a Capacity Resource in a unit-specific offer cap. To be clear, this proposal not propose any changes to the existing default Market Seller Offer Cap values specified in Tariff, Attachment DD, section 6.4, as applied to Existing Generation Capacity Resources and retains the existing rules related to when the Market Seller Offer Cap becomes applicable.

While the unit-specific Market Seller Offer Cap provisions have been in place for quite some time, the aforementioned issue only recently materialized when the unit-specific submissions were reviewed for the 2023/2024 Base Residual Auction. This is

---

[21] While PJM has the ability to make the final determination of whether to accept a reject a requested unit-specific Market Seller Offer Cap, many Capacity Market Sellers withdraw or revise their requested unit-specific Market Seller Offer Cap after the Market Monitor's review and before PJM makes a determination.

because prior to September of 2021, the default Market Seller Offer Cap was based on an assumption of 360 annual expected Performance Assessment Intervals and equal to the product of the Net Cost of New Entry and the average expected Balancing Ratio.[22] Although there were issues with the level of the prior default offer cap, it allowed Capacity Market Sellers to include all risks of taking on a capacity obligation. In contrast, under the current Market Seller Offer Cap rules, any Generation Capacity Resource that is offered by a Capacity Market Seller who fails the three pivotal supplier test (which in practice all Capacity Market Sellers fail) is subject to mitigation and its offer is capped at the resource's unit-specific net ACR. The only way Capacity Market Sellers can now reflect the cost of capacity performance risk is by requesting a unit-specific Market Seller Offer Cap process, proposing, and gaining approval for, a unit-specific CPQR value.[23] As a result, there has been a significant increase in unit-specific offer cap reviews in recent years, which have brought these issues to light.

1. <u>PJM Is Proposing Discrete Tariff Revisions to Establish Additional Approaches to Calculate the Unit-Specific CPQR.</u>

CPQR is one component of the existing unit-specific gross ACR calculation.[24] The existing CPQR provisions are relatively vague and seemingly provides Capacity Market Sellers with latitude to sufficiently allow Capacity Market Sellers to include the company-

---

[22] The Balancing Ratio for a Performance Assessment Interval is the ratio of (i) the total amount of EAS that PJM dispatches in the interval, to (ii) the total amount of capacity that PJM has procured for the corresponding Delivery Year.

[23] *See Indep. Market Monitor for PJM*, 176 FERC ¶ 61,137, at P 69. Under the existing rules, Capacity Market Sellers may elect to utilize the default gross ACR minus the unit-specific EAS offset or submit a unit-specific gross ACR value minus the unit-specific EAS offset.

[24] *See* Tariff, Attachment DD, section 6.8(a). By contrast, the existing default Market Seller Offer Cap, calculated as the default gross ACR minus the net EAS offset, does not contain a CPQR component.

specific nature of valuing non-performance risk so long as they can be supported and justified to the satisfaction of PJM and the Market Monitor. Specifically, the existing language in the Tariff states, in relevant part, that:

> "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.[25]

Additionally, the CPQR provision also allows for:

> [any] 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.[26]

These existing provisions are clearly broad and intended to allow for "complex calculation that depends on the company-specific nature of valuing performance risk and may expand beyond the risk that a resource is subject to Non-Performance Charges in excess of its capacity auction revenue."[27]

Unfortunately, this broad language also leaves room for differences of opinion regarding what actuarial practices are generally used by the industry to model or value risk or what other methodology may be appropriate. This ambiguity has, in certain cases, resulted in unit-specific CPQR values not being accepted given the differences of opinion.

To help refine and clarify the existing CPQR provision, PJM is proposing to add a sentence that would make clear that Capacity Market Sellers may include a CPQR value

---

[25] Tariff, Attachment DD, section 6.8(a).

[26] *Id*.

[27] *Indep. Market Monitor for PJM*, 178 FERC ¶ 61,121, at P 51.

where its risk model, along with supporting documentation, has been "review[ed] by an independent third party entity with experience in evaluating capacity performance insurance policies to confirm that the proposed valuation of risk is consistent with actuarial practices in the industry."[28] This addition is appropriate given that independent third party entities that have experience in evaluating capacity performance insurance policies, such as consultants who evaluate capacity performance insurance or an insurance carrier that issues capacity performance insurance policies, are better positioned to confirm whether a Capacity Market Seller's risk valuation is consistent with actuarial practices used in this industry. The addition of this provision effectively provides another avenue for Capacity Market Sellers to seek a CPQR value with greater confidence that it will be accepted by the Market Monitor and PJM given the independent third party review. To be clear, PJM is not proposing any changes to existing review and approval process for a unit-specific CPQR. Thus, all CPQR values, including under this alternative approach, must continue to be reviewed by both the Market Monitor and PJM and accepted by PJM as is currently the case.

Beyond this addition, PJM is also proposing to include one additional option for Capacity Market Sellers to derive a unit-specific CPQR value by specifying a standard methodology for CPQR in the Tariff. Capacity Market Sellers that seek a unit-specific CPQR under this methodology would simply request PJM to calculate their unit-specific risk cost consistent with the formula specified in the proposed Tariff. This option would result in a calculated CPQR value that is equal to the estimated cost of managing the risks

---

[28] Proposed Tariff, Attachment DD, section 6.8(a).

of Non-Performance Charges multiplied by the annual total net Non-Performance Charges for the resource "based on a probabilistic analysis conducted by the Office of the Interconnection that models the resource's performance under a range of simulated system conditions to measure the distribution of potential annual total net over- and under-performance of the resource."[29] This is appropriate because

> CPQR is generally intended to reflect both expected net penalties and the cost of risk incurred by a risk-averse Market Participant from facing an uncertain distribution of delivery-year penalties and bonus revenues. Competitive Capacity Market Sellers naturally evaluate the capacity price at which they would be willing to accept capacity performance penalty risk.[30]

Under this option, Sell Offers for Capacity Resources owned by Capacity Market Sellers that are deemed to have market power will still be subject to the existing unit-specific review process. The only difference is that when a Capacity Market Seller requests a unit-specific Market Seller Offer Cap and requests a CPQR to be calculated based on this methodology, PJM can calculate the unit-specific CPQR value for the relevant resources for such Capacity Market Seller, consistent with the methodology that is in the proposed Tariff and detailed below. Thus, such Sell Offers from Capacity Market Sellers that are deemed to have market power would still be reviewed by the Market Monitor and approved by PJM.[31]

Under this approach, PJM would conduct a probabilistic analysis of unit-specific performance under a range of system conditions for each resource, using the same

---

[29] *See* proposed Tariff, Attachment DD, section 6.8(a).

[30] Graf Aff. ¶ 93.

[31] Notwithstanding, it is noted that the Commission has explained that a "replacement rate does not *require* the marginal offer to be reviewed and may well not review the marginal offer at all." *Indep. Market Monitor for PJM*, 178 FERC ¶ 61,121, at P 77.

enhanced analytical framework used to study reliability risks and assess resource accreditation. This analysis would yield a distribution of performance during simulated Performance Assessment Intervals, as well as other parameters, such as Balancing Ratio, necessary to assess the distribution of potential net Non-Performance Charges and Performance Payments. The unit-specific risk cost that PJM calculates would represent the estimated cost of managing the risks of Non-Performance Charges, equal to a resource's after tax Weighted Average Cost of Capital ("ATWACC"), which is "calculated as: percent equity * cost of equity + percent debt * debt interest rate * (1- effective tax rate)."[32] As Dr. Graf explains, "the ATWACC represents one reasonable, conservative estimate of those potential costs. The cost of risk and other assumptions would be periodically reviewed to maintain alignment with potentially changing market fundamentals."[33]

The values used to calculate the default cost of risk would be determined consistent with the calculated value used in the capital recovery factor ("CRF") formula in the avoidable project investment recovery ("APIR") component that is detailed in Tariff, Attachment DD, section 6.8(a). Using the same inputs as in the CRF formula in the APIR component for PJM to calculate a default risk cost is appropriate as these values are consistent across PJM. Alternatively, Capacity Market Sellers may substitute their own estimate of a unit-specific risk cost and provide supporting documentation for such estimate. Thereafter, PJM would calculate the unit-specific CPQR value by multiplying the risk cost with the estimated exposure to risk of Non-Performance Charges that PJM

---

[32] Proposed Tariff, Attachment DD, section 6.8(a).

[33] Graf Aff. ¶ 103.

calculates for that resource, based on a probabilistic analysis that models the resource's performance under a range of simulated system conditions.

To determine the estimated annual total net Non-Performance Charges of a resource, PJM would employ a probabilistic model that is also used in the reliability risk analysis and accreditation of resources, or ELCC model. This model "provides a robust and reasonable approach to assess the distribution of potential net Non-Performance Charges a resource may face in the Delivery Year as it already integrates many of the relevant factors that impact the calculation of net Non-Performance Charges."[34] Specifically, these factors include the performance of the resource simulated under a broad range of system conditions and weather scenarios. It also includes the number and timing of modeled Performance Assessment Intervals, which can be simulated in the model when the available supply falls below the load and reserve requirement in an hour, representing a reserve shortage and trigger for a Performance Assessment Interval. The probabilistic model also incorporates parameters that are incorporated into the Balancing Ratio and expected performance of resources to determine shortfall or bonus megawatts during the simulated Performance Assessment Intervals. The other key factors that influence the calculation of net Non-Performance Charges that a resource may face in the Delivery Year are either known values, such as the Non-Performance Charge rate, or are values that will be estimated outside of the model and fed into the analysis, such as the annual stop-loss for the resource.

[34] Graf Aff. ¶ 98.

From that distribution, PJM would take the maximum exposure to Non-Performance Charges at a pre-defined confidence interval typically used in this value of risk analysis (i.e. 95th percentile). That risk exposure, which is generally intended to reflect an extreme value on the tail of the distribution, is then multiplied by an estimated cost of managing the risk to determine the CPQR value. This analysis would yield a distribution of performance during simulated Performance Assessment Intervals, as well as other parameters (Balancing Ratio, etc.) necessary to assess the distribution of potential net non-performance charges and bonuses.

As Dr. Graf explains, "[e]stablishing the threshold at the 95th percentile is commonly accepted as a reasonable measure of a typical extreme value that is placed at risk (with some small probability) when facing the distribution of potential outcomes."[35] The standardized unit-specific default CPQR value, calculated by the Office of Interconnection, would equal the default risk cost multiplied by the resource's quantified risk at the 95th percentile.

In developing this new methodology, PJM consulted with various industry experts that provide insurance policies for risk associated with capacity performance. Based on input from these experts, PJM developed this standardized approach that is consistent with actuarial practices used in the industry. Indeed, the ISO New England Inc.'s ("ISO-NE") internal market monitor "agrees that an industry-standard Value-at-Risk ("VAR") approach is an acceptable framework for participants to manage and measure risk in the context of the PFP capacity market" and further describes that "VAR and similar measures

---

[35] Graf Aff. ¶ 100.

are widely used by financial institutions and businesses to measure risk and determine whether action is needed to bring risks within acceptable corporate risk tolerances."[36]

In conclusion, this approach results in a reasonably calculated CPQR value based on actuarial prices used in the industry today and gives Capacity Market Seller another option of requesting a CPQR value that could be included in their Market Seller Offer Cap. Specifying this methodology in the Tariff also improves transparency regarding the CPQR calculation for all Market Participants, including Capacity Market Sellers as well as load interests with cost concerns.

2. PJM Is Proposing Discrete Tariff Revisions to Allow the Market Seller Offer Cap to Be Reflective of a Standalone Unit-Specific CPQR Component.

In addition to amending the proposed options discussed above, PJM also proposes to establish an additional methodology for calculating a unit-specific Market Seller Offer Cap for those Capacity Resources that would otherwise continue to participate in PJM's EAS markets irrespective of whether they receive a capacity commitment. For these resources, letting the EAS revenues offset the applicable avoidable going-forward costs, including the CPQR component, does not result in mitigation of offers to a competitive offer level for such resources. More specifically, Dr. Graf explains that there are two scenarios under which Capacity Market Sellers' costs could substantially differ:

> The first scenario is that of a Capacity Market Seller who receives insufficient revenues from the energy and ancillary services markets alone to justify the continued profitable operation of a resource. Such a Capacity Market Seller would rationally plan to retire or

[36] Informational Filing for Qualification in the Forward Capacity Market of ISO New England Inc., Docket No. ER15-328-000, Attachment J Methodology Used by IMM in Establishing an Alternative De-List Bid Value When the IMM Rejected Some or All of the Components of the Participant-submitted De-List Bids, at 12 (Nov. 4, 2014).

> mothball their resource if they receive insufficient capacity market revenues to support continued operation. A competitive offer for such a Capacity Resource would reflect the full economic costs of selling capacity: the total gross going-forward avoidable costs of continuing to operate the resource rather than retiring or mothballing, net of the energy and ancillary services revenues that are enabled by the choice to continue operating the resource. . . .
>
> The second scenario is that of a Capacity Market Seller who does receive sufficient revenue from the energy and ancillary services markets to justify continued profitable operation of the resource, without additional capacity revenues. Such a resource is profitable and not at risk of mothball or retirement. However, a competitive Capacity Market Seller['s] . . . offer would reflect economic costs, equal to going-forward net avoidable costs - only those costs that could and would be avoided by not selling capacity. Of the components currently included in the PJM Avoidable Cost Rate, CPQR is clearly avoidable if not committed for capacity.[37]

Thus, "a Capacity Market Seller who plans to continue operating a profitable Capacity Resource regardless of their single-year revenues in the capacity market has economic costs at least as high as CPQR."[38] That is because a Capacity Market Seller who plans to continue operating a resource regardless of receiving a capacity obligation would not avoid any maintenance, operations, labor, or capital costs. These costs are largely only avoided if a resource is mothballed or retired. In this scenario, they are not avoided if the Capacity Market Seller does not accept a capacity commitment. CPQR, by contrast, is avoided if the Capacity Market Seller does not accept a capacity commitment.[39]

Put another way, a resource that would otherwise continue as an energy only resource and does not receive a capacity commitment can avoid the cost of capacity

---

[37] Graf Aff. ¶¶ 80-81.

[38] Graf Aff. ¶ 82.

[39] Graf Aff. ¶ 81.

performance risk altogether because such a resource would not have any risks associated with a potential Non-Performance Charges in the event the resource is not available during a Performance Assessment Interval. By contrast, a resource with a capacity commitment will have capacity performance risk as it would be subject to Non-Performance Charges if the resource is not available during a Performance Assessment Interval.[40] Thus, the cost of the capacity performance risk should be allowed to be reflected in those resources' capacity offers so that the cost of the capacity obligation is no less than the cost associated with the capacity performance risk. Otherwise, Capacity Market Sellers of resources that are subject to the must offer requirement would effectively be required to take on a capacity obligation that ultimately exceeds their avoidable costs. Capacity Market Sellers of resources that are not subject to the must offer requirement are also impacted by this issue because they would either have to submit a Sell Offer that does not include their actual cost of capacity performance Risk or not offer into the RPM Auction at all. Both options lead to inefficient market outcomes and could ultimately risk resource adequacy.

While the unit-specific net ACR calculation provides Capacity Market Sellers with an avenue to include the cost of risk attributable to a capacity performance obligation in the gross ACR calculation, resources with high net EAS offsets can have a net ACR value that may be lower than the CPQR component alone, or even negative. In the case that the net ACR is less than the CPQR, the Capacity Market Seller can still submit a non-zero offer up to the net ACR, but that Market Seller Offer Cap will be less than the risk they believe they face from net Non-Performance Charges. In the case that the net ACR is

[40] The capacity performance risk is a real and verified cost that many Capacity Market Sellers incur such as insurance costs that hedge against this risk.

negative, the Capacity Market Seller is forced to offer at $0.00/MW-day, requiring them to clear in the capacity market regardless of the Capacity Market Seller's perceived risk if they are subject to the must offer requirement. This phenomenon has occurred for all types of units, ranging from thermal to solar and wind resources that have relatively low avoidable costs of maintaining the unit as a Capacity Resource that are mostly or entirely offset by high expected EAS revenues. In these cases, the high EAS offsets often cancel out the CPQR component and result in a net ACR that does not adequately reflect the cost of risks from non-performance charges. When this occurs, a resource would be more profitable without a capacity obligation rather than potentially clearing the capacity market at a level that is confiscatory and less than the cost of risk for being a committed Capacity Resource. Capacity offers should not be mitigated below those levels equal to the natural, profit-maximizing offers of competitive Capacity Market Sellers. This is over-mitigation and disincentivizes participation in the capacity market. For resources that plan to participate in PJM's EAS markets irrespective of whether they receive a capacity commitment, the Market Seller Offer Cap should be equal to only the incremental costs that would be avoided the absence of a capacity obligation.[41] Otherwise, there would be over-mitigation and would result in uneconomic outcomes in the capacity market.[42]

In short, Capacity Market Sellers should be allowed to offer capacity at a level that reflects the resource's economic costs, including any costs that could and would be avoided

---

[41] In most cases, that incremental cost would be limited to the cost of risk associated with capacity performance (i.e., CPQR). That said, if a Capacity Market Seller decides to make an investment and make a resource dual fuel capable to mitigate against the potential risks of non-performance during a Performance Assessment Interval, then such associated costs would be deemed incremental costs that would be avoided in the absence of a capacity obligation.

[42] *See* Graf Aff. ¶ 87.

by not selling capacity. Capacity Market Sellers that offer a Capacity Resource into the capacity market and plan to continue operating the resource, regardless of receiving a capacity commitment, face economic costs of selling capacity that are at least as high as their CPQR. This is because if they accept a capacity commitment at a market clearing price that is less than their CPQR, they would be less profitable than not taking on that capacity commitment at all. Consequently, it follows that the natural, profit-maximizing offer for such a Capacity Market Seller and such a resource is at least as high as CPQR.

To further illustrate, a hypothetical gas unit may have a gross ACR (excluding the CPQR component) of $50/MWh, a CPQR component of $10/MWh, and a net EAS offset of $100/MWh. Under the existing rules, this hypothetical unit would have a unit-specific net ACR of negative $40/MWh, which effectively means the Capacity Market Seller of such a resource would not be allowed to offer above $0/MWh for this unit in the RPM Auctions even though the CPQR cost alone is $10/MWh. Taking into account the must offer requirement, this unit would be required to offer into the capacity market at $0/MWh and potentially end up with a capacity commitment that is worth less than the cost of the non-performance risk. When this occurs, a Capacity Market Seller is effectively required to accept a capacity obligation that reduces their net profits. Such an outcome is clearly confiscatory.

This concern is not limited to those resources with a must offer obligation. Capacity Market Sellers of Intermittent Resources that are not subject to the must offer requirement also face two choices that may not result in economic outcomes: (a) offering into the capacity auction at a level that does not capture the economic costs of the unit or (b) not offering the unit into the capacity market at all. To further illustrate, take a hypothetical wind unit that has a gross ACR (excluding the CPQR component) of $80/MWh, a CPQR component of $20/MWh, and a net EAS offset of $150/MWh. Under the existing rules, this hypothetical unit would have a unit-specific net ACR of negative $50/MWh, which effectively means the Capacity Market Seller of such a resource would not be allowed to offer above $0/MWh for this unit in the RPM Auctions even though the CPQR cost is $20/MWh. In short, the existing tariff rules can result in offsetting CPQR—a component the Commission has allowed. This has the effect of discouraging Intermittent Resources from participating in the capacity market.

To address these concerns and avoid uneconomic over-mitigation, the Market Seller Offer Cap should be no less than CPQR for those resources that would continue to operate and participate in the EAS markets even if they do not receive a capacity commitment. As a result, PJM is proposing a targeted amendment to allow resources that would continue to participate in the EAS markets even if they do not receive a capacity commitment to utilize a unit-specific Market Seller Offer Cap that is based on incremental costs that would be avoided only in the absence of a capacity obligation, such as CPQR, without an offsetting such costs with the resource's expected net EAS revenues.[43]

While CPQR is the most direct example of a cost that can be avoided by not taking on a capacity commitment, there are others that could also apply. For example, if a new requirement was added to become a Capacity Resource, such dual fuel capability to address

[43] *See* proposed Tariff, Attachment DD, section 6.8(d-1) ("Notwithstanding the foregoing, in the case that the Capacity Market Seller has indicated in their submission of a unit-specific Market Seller Offer Cap that the resource will continue to operate and participate in the energy and ancillary services markets during the Delivery Year if not cleared in the capacity market, the Projected PJM Market Revenues shall be zero dollars.").

fuel security or weatherization, such expenses may not be economic for a Generation Owner to incur without adequate capacity revenues to cover the cost of the investment. In a scenario where a resource is net profitable without capacity revenues, incurring the additional costs of dual fuel installation or weatherization are incremental to taking on a capacity commitment and can be avoided by not taking on one.

PJM's proposed revision makes clear that when calculating unit-specific avoidable costs, the avoidable expenses are incremental expenses, such as CPQR, directly required to operate a Generation Capacity Resource that a Generation Owner would not incur if such generating unit were to mothball or retire and not operate or have a capacity obligation in the Delivery Year.[44] In those cases, the Projected PJM Market Revenues would be equal to zero so that the net EAS revenues would not offset the CPQR in those instances.[45] By contrast, Projected PJM Market Revenues would not be equal to zero for a resource that would mothball or retire if it does not receive a capacity commitment. This approach would accomplish the fundamental objective of returning capacity market outcomes to those that would prevail in a competitive market.

In short, as PJM is preserving the penalty structure under capacity performance, it is reasonable to reflect the risk associated capacity performance in the unit-specific Market Seller Offer Cap. Moreover, from a policy perspective, the proposed revision appropriately incentivizes Capacity Resources to be offered into the capacity market as opposed to becoming an energy only resource. Capacity commitments in the PJM capacity market is

---

[44] Proposed Tariff, Attachment DD, section 6.8(b) and Proposed Tariff, Attachment DD, section 6.7(d).

[45] Proposed Tariff, attachment DD, section 6.8(d-1).

the key tool that PJM utilizes to procure resource adequacy. Accordingly, the proposed change removes disincentives for Capacity Resources to become energy only resources.

Finally, PJM's proposal here is entirely consistent with the rules that the Commission has adopted for ISO-NE. Specifically, ISO-NE's Market Rule 1 provides that "[i]n the case of a resource that has indicated in the submission of a Static De-List Bid that the resource *will not be participating in the energy and ancillary services markets during the Capacity Commitment Period, [the expected annual infra-marginal rents] shall be calculated by subtracting all submitted cost data representing the cumulative expected cost of production* (total expenses related to the production of energy, e.g. fuel, actual consumables such as chemicals and water, and, if quantified, incremental labor and maintenance) from the Existing Generating Capacity Resource's total ISO market revenues. *In the case of a resource that has indicated in the submission of a Static De-List Bid that the resource will be participating in the energy and ancillary services markets during the Capacity Commitment Period, this value shall be $0.00.*"[46] ISO-NE's Tariff further specifies that the annual going forward costs "are the expected costs and capital expenditures that might otherwise be avoided or not incurred if the resource were not subject to the obligations of a resource with a Capacity Supply Obligation during the Capacity Commitment Period (i.e., maintaining a constant condition of being ready to respond to commitment and dispatch orders)."[47] In adapting these revisions, ISO-NE explained to the Commission that when a resource will participate in the energy and ancillary services markets, the infra-marginal rent value used in the net risk-adjusted going

---

[46] ISO-NE Market Rule 1, section III.13.1.2.3.2.1.2.A (emphasis added).

[47] ISO-NE Market Rule 1, section III.13.1.2.3.2.1.2.A.

forward costs calculation would be equal to zero "because if a resource remains in the energy market even if it leaves the capacity market, it does not lose its energy market revenues."[48] These ISO-NE Tariff provisions that the Commission accepted as just and reasonable effectively provide for the same approach that PJM is proposing here.[49] Dr. Graf reviewed ISO-NE's Tariff and states that "the proposed PJM approach is entirely consistent with ISO-NE's approved methodology today."[50] Therefore, the Commission should similarly accept the proposed revisions here.

B. PJM Proposes Revised Default Market Seller Offer Caps and Also Allowing for Unit-Specific Offer Caps for Planned Generation Capacity Resources.

Through this filing, PJM is also proposing to amend the default Market Seller Offer Cap that is applied to Planned Generation Capacity Resources that are subject to mitigation, as well as an ability for Capacity Market Sellers of Planned Generation Capacity Resources to seek a unit-specific Market Seller Offer Cap.

While the existing Market Seller Offer Cap rules are primarily focused on market power mitigation of Existing Generation Capacity Resources, the rules today also mitigate against market power for Planned Generation Capacity Resources in limited circumstances. Specifically, a Planned Generation Capacity Resource is subject to being offer capped when (1) all Sell Offers based on Planned Generation Capacity Resources provide Unforced Capacity in an amount that is less than "two times the incremental

---

[48] Forward Capacity Market Redesign Compliance Filing and Request for Waiver of Compliance Obligation, or, In The Alternative, Limited Filing Pursuant to Section 205 of the Federal Power Act of ISO New England Inc., Docket No. ER12-953-001, at 32 (Dec. 3, 2012).

[49] *ISO New England Inc.*, 142 FERC ¶ 61,107 (2013).

[50] Graf Aff. ¶ 91.

quantity of new entry required to meet the LDA Reliability Requirement" and (2), there are less than "two unaffiliated suppliers have submitted Sell Offers for Planned Generation Capacity Resources in such LDA."[51] When this occurs, a Planned Generation Capacity Resource's Sell Offer must be less than "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.[52]

Thus, the existing Market Seller Offer Cap rules for Planned Generation Capacity Resources effectively sets an offer cap for such resources based on offers from other Planned Generation Capacity Resources of the same asset type in that same auction or Sell Offers from similar resources from prior auctions. Since the offer cap is based on other offers during the same auction, the offer cap for Planned Generation Capacity Resources will not be known until after the auction window closes, and a Capacity Market Seller may be subject to previous market conditions by setting an offer cap from prior auctions. This creates a problem of timely information for the Capacity Market Seller, as the Capacity Market Seller can only guess whether the offer cap will be above their costs after offering. Moreover, both of these options are unlikely to be representative of the costs of a Planned Generation Capacity Resources that are ultimately subject to the Market Seller Offer Cap.

---

[51] Tariff, Attachment DD, section 6.5(a)(ii)(B).

[52] Tariff, Attachment DD, section 6.5(a)(ii)(C).

In some cases, this has resulted in certain Planned Generation Capacity Resource to being limited to submit Sell Offers that were well below the estimated Net Cost of New Entry ("Net CONE") of the resource. When that occurs, the Capacity Market Seller would have to elect to lower their Sell Offer to what may be a price that is well below their actual costs and hope the clearing price is still high enough to support their costs. Alternatively, the Capacity Market Seller would have to retract their Sell Offer from the RPM Auction rather than being able to reflect a Sell Offer that more reasonably reflects the resource's cost or request a unit-specific offer cap based on the resource's actual Net CONE. Both options are inefficient and could risk resource adequacy to the extent the auction clears at a level that is below the reliability target in an LDA.

To address against such undesirable outcomes, PJM proposes to amend the default offer cap when a Planned Generation Capacity Resource is subject to being offer capped so that it will be equal to the default Net CONE values for the applicable technology in the Zone for which Sell Offer was submitted.[53] Although the existing Market Seller Offer Cap rules currently provide default gross ACR values for Existing Generation Capacity Resources, it would not be appropriate to apply those gross ACR values to Planned Generation Capacity Resources given that their costs are different from Existing Generation Capacity Resources.

Thus, consistent with how previously uncleared resources and previously cleared resources are treated for purposes of the MOPR, PJM proposes to apply the same default

[53] To be clear, the proposed change to the default Market Seller Offer Cap as applied to Planned Generation Capacity Resources is entirely separate and distinct from the Commission's recent orders regarding the default Market Seller Offer Cap as applied to Existing Generation Capacity Resources. *See Independent Market Monitor for PJM*, 178 FERC ¶ 61,121.

gross CONE values specified in the MOPR provisions for Planned Generation Capacity Resources that are subject to the Market Seller Offer Cap. The calculation of the default Net CONE value would also be calculated consistent with the existing rules for previously uncleared resources that are subject to the MOPR.[54] This provides an approximate estimate of the Net CONE values that are more correlated with the actual costs of the relevant resource type that is subject to the Market Seller Offer Cap.

For those resource types where no default Net CONE value exists, such as steam, oil, and diesel units, PJM proposes to set the default offer cap based on the Net CONE, which is used in setting the VRR Curve for the applicable Delivery Year and LDA of such resource. This is appropriate since it would still allow the Capacity Market Sellers of such resource to offer the resource into the RPM Auction while allowing the Net CONE of the Reference Resource provide a reasonable estimate for the costs of new entry for this limited group of resources.

Finally, just like the existing unit-specific Market Seller Offer Cap that can be requested for Existing Generation Capacity Resources, PJM proposes to allow Capacity Market Sellers of Planned Generation Capacity Resources to seek a unit-specific offer cap that is based on the Net CONE of such resource utilizing the same unit-specific Net CONE methodology that is already documented in the Tariff for new resources that are subject the MOPR.[55] The review process and approval timing for the unit-specific Net CONE of Planned Generation Capacity Resources would be consistent with the existing provisions for seeking a unit-specific Market Seller Offer Cap. The proposed PJM changes will allow

[54] *See* Tariff, Attachment DD, section 5.14(h-2).

[55] *See* Tariff, Attachment DD, section 5.14(h-2)(4)(B).

Capacity Market Sellers to be aware of potential mitigation pricing levels well before the auction in order to appropriately reflect their costs.

To effectuate the foregoing, PJM proposes the following revisions to Tariff, Attachment DD, section 6.5(a)(ii)(C), as shown in blackline below:

> 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 ~~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 default Net CONE value for the applicable technology, as calculated in accordance with Tariff, Attachment DD, section 5.14(h-2), ~~applicable~~ for such Delivery Year in the ~~LDA~~ Zone for which such Sell Offer was submitted; or 2) if there is no default Net CONE value for the applicable technology for such Delivery Year in the Zone, the Net CONE that is used in setting the VRR Curve applicable for such Delivery Year in the LDA for which such Sell Offer was submitted. Notwithstanding the above, the Sell Offer of a Planned Generation Capacity Resource shall not be rejected if offered at or below a unit-specific offer price that is calculated in accordance with Tariff, Attachment DD, section 5.14(h-2)(4)(B), and submitted and approved in accordance with Tariff, Attachment DD, section 6.4(b). ~~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.

C. PJM Proposes Discrete Tariff Revisions to Allow PJM, After the Market Monitor's Review, to Determine a Unit-Specific Offer Cap Based on Information Provided by Capacity Market Sellers.

To allow for the orderly administration of the RPM Auctions, the Tariff sets forth various deadlines for Capacity Market Sellers, the Market Monitor, and PJM to submit and complete various reviews, respectively, in advance of the auction. As relevant to the calculation of a unit-specific Market Seller Offer Cap, the Tariff imposes a deadline of 120 days prior to the RPM Auction for Capacity Market Sellers that elect to submit a request for a unit-specific offer cap.[56] The Tariff then provides:

> The Market Monitoring Unit must attempt to reach agreement with the Capacity Market Seller on the appropriate 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. If such agreement cannot be reached, then the Market Monitoring Unit shall inform the Capacity Market Seller and the Office of the Interconnection of its determination of the appropriate 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.[57]

Thereafter, the Capacity Market Seller is required to notify the Market Monitor and PJM whether or not it agrees with the unit-specific offer cap calculated by the Market Monitor "no later than eighty (80) days prior to the commencement of the offer period for the applicable RPM Auction."[58] PJM is subsequently required to review the data submitted

---

[56] Tariff, Attachment DD, section 6.4(b).

[57] Tariff, Attachment M-Appendix, section E.2.

[58] Tariff, Attachment DD, section 6.4(b).

by the Capacity Market Seller and make a determination whether to *accept or reject* the requested unit-specific Market Seller Offer Cap by no later than 65 days prior to the commencement of the offer period for the applicable RPM Auction.[59]

Under these existing Tariff rules, in reviewing a requested unit-specific Market Seller Offer Cap, the Market Monitor is allowed to "reach agreement with the Capacity Market Seller on the appropriate level of the Market Seller Offer Cap"[60] while PJM's review and determination is limited to "accept or reject the requested unit-specific Market Seller Offer Cap."[61] These rules confine PJM's ability to accept a unit-specific Market Seller Offer Cap that differs from any level that is requested by the Capacity Market Seller. Based on recent experience, this limited ability to either accept or reject a unit-specific Market Seller Offer Cap has proven to be inefficient and can result in a Market Seller Offer Cap being rejected outright even though PJM may agree with certain components of the overall requested unit-specific offer cap. For example, under the existing rules, if PJM agrees with a Capacity Market Seller's CPQR, avoidable maintenance costs, taxes, and carrying charges, but not with the fuel availability expense, the entire requested unit-specific Market Seller Offer Cap would be rejected and the Capacity Market Seller would be limited to the default Market Seller Offer Cap value (which can be equal to $0/MW-day in many cases).

---

[59] *Id*.

[60] Tariff, Attachment M-Appendix, section E.2.

[61] Tariff, Attachment DD, section 6.4(b).

To avoid such outcomes going forward, PJM proposes a simple revision that would also allow PJM to "calculate an alternative unit-specific Market Seller Offer Cap based on the submitted documentation."[62] This would allow PJM to accept certain components of a unit-specific Market Seller Offer Cap that are consistent with the Tariff, rather than rejecting the entire requested unit-specific Market Seller Offer Cap outright. To be clear, this revision does not in any way alter the existing Tariff provisions that allow "the Market Monitoring Unit and the relevant Capacity Market Seller [to] mutually agree on the value of such Market Seller Offer Cap."[63] This provision also does not change the respective roles of PJM and the Market Monitor with regard to this process as it currently exists today. Specifically, PJM, with consideration of the Market Monitor's input and determination, has ultimate approval authority of all Market Seller Offer Caps and the Market Monitor has the ability to escalate any disagreements on a PJM-approved Market Seller Offer Cap to the Commission for potential resolution.[64] Moreover, any of the components that PJM does accept must consistent with the provisions detailed in the Tariff. This revision simply allows PJM to calculate and approve a unit-specific offer based on components that are consistent with the Tariff while rejecting others that are not.

D. PJM Proposes Discrete Tariff Revisions that Would Allow Requests for Unit-Specific Segmented Market Seller Offer Caps.

Through this filing, PJM also proposes to allow Capacity Market Sellers to submit unit-specific Market Seller Offer Caps that reflect incremental costs of having a capacity

---

[62] *See* proposed Tariff, Attachment DD, section 6.4(b).

[63] Tariff, Attachment DD, section 6.4(b).

[64] Tariff, Attachment DD, section 6.4(b) and Tariff, Attachment M-Appendix, section M(E).

obligation across different segments of a unit. Under the existing rules, a Capacity Market Seller's 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."[65] However, the existing rules do not explicitly describe how a unit-specific Market Seller Offer Cap should be calculated for the various offer segments should a Capacity Market Seller seek to submit differing price-quantity pairs.

The ability to request segmented Market Seller Offer Caps is appropriate because there may be incremental costs of risks associated with offering additional MWs from the same unit in certain instances. For example, certain Capacity Resources, such as Intermittent Resources, or a run-of-river hydro plant with limited pooling capability, can face greater uncertainty in the availability of their megawatts at the upper end of their output compared with the lower end of such output during Performance Assessment Intervals, which can drive varying levels of performance risk and associated costs across different segments on the unit.

In these situations, it is appropriate to allow Capacity Market Sellers to request a unit-specific Market Seller Offer Cap on a segmented basis. To obtain a segmented offer cap, a Capacity Market Seller "must provide adequate justification for the use of a segmented offer cap with supporting documentation and calculations for the Market Seller Offer Cap of each segment" which are to be calculated in accordance with the unit-specific offer cap provisions in Tariff, Attachment DD, section 6.8.[66] While a Capacity Market Seller may seek to include incremental expenses directly required to operate a Generation

---

[65] Tariff, Attachment DD, section 5.6.1(b).

[66] Proposed Tariff, Attachment DD, section 6.4(e).

Capacity Resource that a Generation Owner would not incur if such generating unit were to mothball or retire in their first segmented offer, the costs of risk associated with offering additional megawatts as capacity are different from those incurred to keep the unit from mothballing or retiring. Instead, the cost of capacity performance risk may increase as more MWs are offered as capacity due to the operating characteristics of a resource.

Consistent with these principles for allowing segmented offer caps, the proposed rules specify that the first segment may include "incremental expenses directly required to operate a Generation Capacity Resource that a Generation Owner would not incur if such generating unit were to mothball or retire."[67] However, all other offer segments can only reflect the incremental costs that would be avoided only in the absence of a capacity obligation for each of those segments.[68] This limitation reflects the fact that once any portion of the resource is committed, the relevant costs to operate the generating unit are no longer avoidable, such that the remaining offer segments beyond the first should only reflect the avoidable, incremental costs associated with taking on a capacity obligation for those segments, and thereby prevents Capacity Market Sellers from including duplicative expenses in multiple offer segments.

II. REVISIONS TO THE CAPACITY PERFORMANCE CONSTRUCT ARE APPROPRIATE TO ACHIEVE AND ENHANCE RESOURCE ADEQUACY

A. PJM Proposes to Clarify Expectations Regarding Excusals from Performance Shortfalls.

PJM's recent experience with Winter Storm Elliott highlighted the need for additional clarity regarding the circumstance under which a Capacity Market Seller or

---

[67] *Id*.

[68] *Id*.

Locational UCAP Seller may be excused from the calculation of a performance shortfall for a Performance Assessment Interval. Despite the strictly circumscribed excusals set forth in Tariff, Attachment DD, section 10A(d), some Capacity Market Sellers still alleged that they met the requirements for an excusal because, despite being offline or unavailable during Winter Storm Elliott, they were "not scheduled to operate by the Office of the Interconnection."[69]

The Commission has consistently held that narrowly tailored excusals from Non-Performance Charges are just and reasonable, and "[c]reating . . . categorical exemptions may result in unintended loopholes. Resources need to consider these possibilities in assessing risk and structuring their Capacity Performance offers."[70] Eliminating perceived loopholes or workarounds to the limited excusals currently set forth in the Tariff can only serve to further the goals of RPM by ensuring that Capacity Market Sellers and Locational UCAP Sellers are on sure footing about their performance obligations during a Performance Assessment Interval. PJM therefore proposes to add new Tariff, Attachment DD, section 10A(d-1) to make explicit the circumstances under which a Capacity Market Seller may be excused from calculation of Non-Performance Charges.

As set forth below, PJM is proposing to continue to strictly circumscribe excusals for planned and maintenance outage MW approved by PJM. Additionally, as set forth in proposed Tariff, Attachment DD, section 10A(d-1), online units will now be excused if they are *dispatched by PJM* to operate below their expected performance for reasons *other than* operating parameter limitations submitted in the resource's operating parameters.

---

[69] Tariff, Attachment DD, section 10A(d).

[70] *PJM Interconnection, L.L.C.*, 155 FERC ¶ 61,157, at P 110.

This retains the existing rule that a resource will be excluded in the calculation of a performance shortfall "to the extent such scheduling was not solely due to any operating parameter limitations submitted in the resource's schedule on which it was dispatched."[71]

However, PJM is removing the existing language where a resource would be considered in the calculation of performance shortfall where "the seller's submission of a market based offer [is] higher than its cost-based." This is appropriate because a Market Seller's cost-based offer would only come into consideration when such Market Seller fails the three pivotal supplier test and is deemed to have market power. When a Market Seller does not have market power, PJM does not consider the cost-based offer when dispatching a resource. Thus, it would be inappropriate to penalize a Capacity Market Seller when it does not have market power and is scheduled by PJM on its market based offer. This change will also improve the incentive for resources to follow that dispatch instead of an artificial MW point that is related to a different cost schedule on which the resource was not dispatched.

In addition to this revision, PJM also proposes to make clear that if a unit is offline during a Performance Assessment Interval, it will be included in the performance shortfall calculation unless PJM dispatch *affirmatively denies* that unit's request to come online. This will help to avoid future litigation that may arise during capacity emergencies where a resource argues it should not be penalized because it was never dispatched by PJM. During a capacity emergency, all resources should come online to help with such emergency and only those resources that PJM affirmatively directs not to come online due

---

[71] *See* proposed Tariff, Attachment DD, section 10A(d-1).

to system constraints or other operational reasons should be excused from Non-Performance Charges. Based on the foregoing, PJM proposes to the following Non-Performance Charge exception language in Tariff, Attachment DD, section 10A(d-1) beginning with the 2025/2026 Delivery Year:

> (d-1). Notwithstanding subsection (c) above, effective with the 2025/2026 Delivery Year and subsequent Delivery Years, a Capacity Resource or Locational UCAP of a Capacity Market Seller or Locational UCAP Seller shall not be considered in the calculation of a Performance Shortfall for a Performance Assessment Interval to the extent such Capacity Resource or Locational UCAP was unavailable during such Performance Assessment Interval solely because the resource on which such Capacity Resource or Locational UCAP is based was on a Generator Planned Outage or Generator Maintenance Outage approved by the Office of the Interconnection. <u>Further, a Capacity Resource that was scheduled to operate at a level below its expected performance shall also be excluded from the calculation of a Performance Shortfall for a Performance Assessment Interval to the extent such scheduling was not solely due to any operating parameter limitations submitted in the resource's schedule on which it was dispatched.</u> <u>Notwithstanding the foregoing, except for a Capacity Resource that is on a Generator Planned Outage or Generator Maintenance Outage approved by the Office of the Interconnection,</u> <u>a Capacity Resource that is offline during a Performance Assessment Interval shall be included in the calculation of a Performance Shortfall unless the Office of the Interconnection affirmatively denies a request to come online for such resource</u>. In addition, notwithstanding subsection (c) above, a Price Responsive Demand registration shall not be considered in the calculation of a Performance Shortfall for a Performance Assessment Interval when the PRD Curve associated with such registration in the PJM Real-time Energy Market indicates a price point where no demand reduction is expected at the real-time LMP recorded during the Performance Assessment Interval.

These changes provide needed clarity to the narrowly limited circumstances under which a resource may be excused from the calculation of a performance shortfall. As evidenced during Winter Storm Elliott, Capacity Resources must have a clear understanding of the conditions warranting excusal from the calculation of a performance shortfall before a Performance Assessment Interval occurs. Strengthening the current rules to more sharply define the limitations on excusals will reduce the potential litigation as to whether a resource is properly excused. The proposed changes also eliminate ambiguity around whether a resource that is offline during a Performance Assessment Interval may be excused from performance based on conversations with PJM dispatch: unless the resource attempts to come online and is affirmatively directed not to, it will be assessed for the performance shortfall. This requirement makes clear that unless affirmatively directed by PJM not to come online, offline resources with capacity commitments will be exposed to Non-Performance Charges[72] during a Performance Assessment Interval, and PJM dispatch can focus its attention on providing grid reliability.

B. PJM Proposes Revisions to Exclude in the Balancing Ratio Calculation Capacity Resources that are Excused from Non-Performance Charges.

PJM also proposes to amend the resources that are counted in the Balancing Ratio, which is used in calculating the Non-Performance Charges and Performance Payments.[73] To that end, PJM proposes straightforward modifications to the Balancing Ratio formula to reflect changes that will allow better balance the penalty rate during Performance Assessment Intervals. In particular, in keeping with the above-described changes to PJM's capacity performance construct, PJM proposes to modify the formula for calculation of the Balancing Ratio,[74] which is used in determining the level of Expected Performance from

---

[72] Included in this filing, PJM is also proposing to make explicit in Tariff, Attachment DD, section 10A(e) that Non-Performance Charges are simply auction clearing revenue adjustments and do not constitute a penalty rate or penalty provision. While this is consistent with the existing rule and interpretation of this provision, PJM believes it is prudent to make the Tariff more explicit to prevent potential arguments that may be raised in the context of potential bankruptcies.

[73] *See* proposed Tariff, Attachment DD, section 10A(c).

[74] Proposed Tariff, Attachment DD, section 10A(c).

committed generation during Performance Assessment Intervals.[75] As Dr. Graf explains, the Balancing Ratio is intended to capture the amount of generation needed from committed resources to meet system load during a Performance Assessment Interval by dividing the total amount of generation needed by the total amount of committed generation during the event.[76] For example, if system load during a Performance Assessment Interval is 120 GW, and the total amount of committed generation on the system is 160 GW, the Balancing Ratio for the Performance Assessment Interval would be set at 75 percent.[77]

Specifically, PJM proposes to exclude from the Balancing Ratio the megawatts of committed Generation and Storage Capacity Resources that are excused from the calculation a performance shortfall for a Performance Assessment Interval.[78] As Dr. Graf demonstrates, "[i]f one-quarter of the resources with Actual Performance below Expected Performance were excused, the total penalties collected would be reduced by roughly one-quarter. This reduces the available bonus pool to be distributed across resources with Actual Performance above Expected Performance."[79] Thus, excluding excused resources from the demoninator of the Balancing Ratio improves the symmetry between the Performance Payment and Non-Performance Charge and "better allows market

---

[75] Specifically, PJM determines Expected Performance by multiplying the Balancing Ratio by the Resource Committed Capacity, represents the total megawatts of committed Unforced Capacity of a resource. *See* Tariff, Attachment DD, section 10A(c).

[76] Graf Aff. ¶ 57; *see* Tariff, Attachment DD, section 10A(c).

[77] Graf Aff. ¶ 57; *see* Tariff, Attachment DD, section 10A(c).

[78] *See* proposed Tariff, Attachment DD, section 10A(c).

[79] Graf Aff. ¶ 66.

participants with over-performing resources to use the bonus revenues collected for such over-performance to net against non-performance charges on a MW-for-MW basis."[80]

C. PJM Proposes a New Performance Assessment Interval Obligation Transfer to Provide Capacity Market Sellers With Better Management of Capacity Performance Risk.

PJM proposes to introduce a new Performance Assessment Interval obligation transfer for Capacity Market Sellers ("PAI Obligation Transfer").[81] The PAI Obligation Transfer would allow exchange of the Performance Assessment Interval obligations associated with committed unforced Capacity on a more granular (i.e., interval) basis than provided for under the current rules. Beginning with the 2025/2026 Delivery Year, the PAI Obligation Transfer would allow Market Participants to adjust the expected performance of a Capacity Resource by entering into a bilateral capacity obligation transaction for the purchase and sale of a specified megawatt quantity of committed capacity that is subject to the performance obligations and provisions of Tariff, Attachment DD, section 10A.[82] As result of the transaction, the seller's PAI obligation on a resource is transferred to and received by the buyer's resource.[83]

As proposed, PAI Obligation Transfers must be reported to PJM, where the parties to the transaction must identify: (1) the transferring resource of the seller from which the megawatts are being sold, (2) the megawatt quantity of committed capacity to be

[80] Graf Aff. ¶ 67.

[81] *See* proposed Tariff, Attachment DD, section 4.6(f).

[82] *See* proposed Tariff, Attachment DD, section 4.6(f).

[83] To be clear, an entity could act as both the buyer and seller in the PAI Obligation Transfer transaction if it has multiple resources in its own portfolio and seeks to reassign Performance Assessment Interval obligations to qualifying resources within its own portfolio.

transferred, (3) the effective time period for which the PAI Obligation Transfer applies, which may be set on an interval basis, and (4) the receiving Capacity Resource of the buyer that will assume the performance obligation of the transferred capacity. Such transactions must be reported and approved by both parties prior to the start of the effective time period of the transfer.[84] The effect of a PAI Obligation Transfer is to modify the committed capacity and resulting expected performance of the transferring and receiving resources when assessing the performance shortfall or bonus during a Performance Assessment Interval.[85] As a result of the transaction, the transferring resource (i.e., seller) will have a reduction in expected performance and the receiving resource (i.e., buyer) will have an increase in expected performance during Performance Assessment Intervals that occur within the effective time period of the transfer.[86] The performance obligations of the transferred capacity and any associated Non-Performance Charges pass to the buyer; provided, however, the seller must guarantee and indemnify the Office of the Interconnection, PJMSettlement, and PJM Members for any failure by the buyer to pay any Non-Performance Charges owed to PJMSettlement associated with the transferred capacity.[87]

For a PAI Obligation Transfer to be accepted by the Office of the Interconnection and take effect for a Performance Assessment Interval, the following criteria must be

---

[84] *See* proposed Tariff, Attachment DD, section 4.6(f)(i).

[85] To be clear, a PAI Obligation Transfer is limited to transferring resource performance during performance Assessment Intervals. Such a transfer does not impact the receiving Capacity Resource's other obligations as a committed Capacity Resource, including but not limited to testing requirements, energy market must offer obligation, and deficiency check.

[86] *See* proposed Tariff, Attachment DD, section 4.6(f)(ii).

[87] *See* proposed Tariff, Attachment DD, section 4.6(f)(iii).

satisfied: (i) the receiving resource reported in the PAI Obligation Transfer must provide the same locational value of capacity as the transferring resource (taking into consideration the remaining import capability into Locational Deliverability Areas), and both resources must be included in the area of the Performance Assessment Interval; and (ii) the resulting quantity of capacity that is subject to performance obligations on the receiving resource reported in the PAI Obligation Transfer cannot exceed the installed capacity or capacity interconnection rights of such resource.[88] All payments and related charges associated with a PAI Obligation Transfer will be arranged between the parties to the transaction.[89] PJM, PJMSettlement, and the Members will not assume financial responsibility for the failure of a party to perform obligations owed to the other party under a PAI Obligation.[90] These proposed requirements for the PAI Obligation Transfer are similar to, and generally styled after, existing bilateral transactions set forth in Tariff, Attachment DD, section 4.6, and previously approved by the Commission.[91]

The proposed PAI Obligation Transfer will allow for more granular transactions of Performance Assessment Interval obligation associated with committed Capacity Resource. As Dr. Graf explains,

> By allowing for more granular transfers of the PAI obligations associated with committed UCAP, Capacity Market Sellers are granted increased flexibility to adjust their positions and manage their exposure to Capacity Performance risk in response to both unexpected and expected events. Capacity Market Sellers can mitigate their exposure to Capacity Performance risk by reacting

---

[88] *See* proposed Tariff, Attachment DD, section 4.6(f)(iv).

[89] *See* proposed Tariff, Attachment DD, section 4.6(f)(v).

[90] *Id*.

[91] *See* Tariff, Attachment DD, sections 4.6(a), (b) and (c).

> promptly to unforeseen changes in their expected availability, such as when they face a higher probability of forced outages, and transacting the PAI obligation with a different market participant who is available and able to essentially offer insurance against under-performance during potential PAIs.[92]

In other words, the proposed PAI Obligation Transfer will enable Capacity Market Sellers to more effectively manage capacity performance risk, thereby reducing Capacity Performance Quantifiable Risk. The proposal also provides for greater opportunity for the financial Performance Assessment Interval obligation to be backed by a physical hedge. More specifically, Dr. Graf explains that:

> With the proposed changes, Capacity Market Sellers can more closely match their financial obligations with the expected availability of their physical resources. This alignment both reduces individual participants' Capacity Performance risk and also helps to ensure that there is a physical backing for financial commitments, enhancing the system's reliability and robustness. Having a physical hedge means that the system can count on actual energy or capacity being available when required, reducing the risk of shortages or reliability issue. Furthermore, this alignment means that market sellers may be able to reduce their total exposure to uncertainty in Capacity Performance bonus revenues and non-performance charges, thus reducing their overall Capacity Performance Quantitative Risk.[93]

D. PJM Proposes to Amend the Rules Regarding Eligibility for Performance Payments.

As noted in the introduction, the proposed changes described within this section II.D may be severable from the rest of this filing if deemed necessary by the Commission. Under the existing capacity performance construct, any resource, including an energy import transaction, is eligible for Performance Payments if its actual performance exceeds

---

[92] Graf Aff. ¶ 73.

[93] Graf Aff. ¶ 74.

their expected performance. This generally means that a Capacity Market Seller of a committed Capacity Resource is eligible for Performance Payments based on the resource's actual output that is in excess of the MW quantity of such resource's capacity commitment during a Performance Assessment Interval. Additionally, for resources that do not have a capacity commitment, the Performance Payment under the existing rules is effectively equal to any MW output of such a resource adjusted for certain ancillary service commitments. The current rules regarding Performance Payment eligibility also allow for Performance Payments to import transactions from neighboring Balancing Authorities.

Through this filing, PJM proposes to amend the eligibility of Performance Payments so that only committed Generation Capacity Resources that outperform their expected performance during a Performance Assessment Interval, up to their committed level of installed capacity, are eligible to receive Performance Payments.[94] To that end, PJM also similarly proposes to cap the actual performance for Demand Resources, Price Responsive Demand, and Energy Efficiency Resources to the installed capacity commitment for such resources.[95] This would effectively preclude Demand Resources, Price Responsive Demand, and Energy Efficiency Resources from being eligible to receive Performance Payments, regardless of whether such resources have a capacity commitment. Additionally, any other uncommitted resource, regardless of whether they are Capacity

---

[94] *See* proposed Tariff, Attachment DD, section 10A(g).

[95] *See* proposed Tariff, Attachment DD, section 10A(c).

Resources or energy only resources would also not be eligible for Performance Payments during a Performance Assessment Interval.[96]

For committed Generation Capacity Resources, the portion of the resource's output that would be eligible for Bonus Performance would be the installed capacity equivalent of the committed megawatts of unforced capacity.[97] For instance, if a resource that has 100 megawatts of installed capacity has 80 MW of total accredited UCAP, then the entire resource (up to the 100 MW of installed capacity) is eligible to receive Performance Payments depending on the level of the Balancing Ratio and dispatch instructions from PJM during a Performance Assessment Interval. If the same resource were only committed for 40 MW of its total 80 MW of accredited UCAP, it would only be eligible to receive Performance Payments for up to the first 50 MW (half) of its output as the remaining 50 MW are uncommitted installed capacity.

The proposed changes on eligibility for Performance Payments are appropriate because: (1) it provides greater economic incentives for resources to participate in and submit Sell Offers that clear PJM's capacity market; (2) payments to resources that have not taken on a capacity commitment should be made through the EAS market rather than by diverting capacity revenues to them; and (3) limiting the eligibility of Performance Payments to only committed Capacity Resources aligns with the current formulation of the Market Seller Offer Cap which does not permit opportunity costs to be included.

---

[96] *See* proposed Tariff, Attachment DD, section 10A(g). To be clear, Capacity Resources that are the subject of a PAI Obligation Transfer are deemed to have a commitment for the relevant period and would be subject to potential Non-Performance Charges and Performance Payments based on their actual performance during a Performance Assessment Interval.

[97] *See* proposed Tariff, Attachment DD, section 10A(c).

1. Limiting Performance Payments to Committed Generation Capacity Resources Provides Appropriate Economic Incentives for Resources to Participate and Clear in the Capacity Market.

PJM's capacity market is designed to secure "adequate resources to meet a target loss of load metric."[98] In other words, unlike energy only resources or uncommitted Capacity Resources, PJM can count on committed Capacity Resources at all times during a Delivery Year. This is because committed Capacity Resources are subject to, *inter alia*, recallability requirements, testing requirements, accreditation rules, and financial penalties for during Performance Assessment Intervals.

The current eligibility for Performance Payments include supply such as non-firm import transactions from neighboring Balancing Authorities not associated with the pseudo-tied resources and energy-only resources that do not have Capacity Interconnection Rights. These types of supply do not even meet the resource-specific qualifications to be a Capacity Resource and therefore should not be eligible to receive payments as if they are, especially when the compensation to them stands to weaken the performance incentives for those that met the qualifications and took on the performance risk.

Limiting the pool of resources that are eligible for Performance Payments to only committed Capacity Resources provides a greater economic incentive for resources to be offered into the RPM Auctions, along with the incentive the clear the RPM Auctions. This is because the Performance Payments would only be limited to committed Capacity Resources so the rate of any potential Performance Payments would increase for every megawatt of over-performance during a Performance Assessment Interval. In other words,

---

[98] Graf Aff. ¶ 5.

limiting Performance Payments to only committed Generation Capacity Resources "reduces the capacity revenues transferred to non-committed and non-capacity resources during Performance Assessment Intervals, making it relatively more attractive to accept a capacity commitment and the corresponding obligations."[99] Such additional incentives will spur further competition in PJM's capacity market to help foster a robust pool of resources that will help procure resource adequacy at competitive market outcomes for the PJM Region.

To be clear, while the eligibility of Performance Payments are proposed to be narrowed, the existing concept of how Performance Payments are calculated would remain unchanged for committed Capacity Resources. Specifically, committed Capacity Resources would continue to be eligible to receive Performance Payments if their actual performance exceeds their committed capacity quantity. Thus, since Capacity commitments are based on the MWs of Unforced Capacity, the MWs that are eligible for Performance Payments would be equal to the metered output of energy from a committed Capacity Resource compared to the Installed Capacity equivalent of the resource's committed Unforced Capacity.

2. Limiting the Bonus Pool to Cleared Capacity Resources Will Strengthen Performance Incentives for Capacity Resources and Enhance Reliability.

It is anticipated that certain entities may argue that limiting the Performance Payments to only committed Generation Capacity Resources could diminish system reliability because uncommitted resources would no longer be incentivized to perform

[99] Graf Aff. ¶ 58.

during Performance Assessment Intervals. Such assertions are unfounded. By creating a stronger incentive for Capacity Resources to be offered into the capacity market (as opposed to serving only as energy only resources) and to exceed their committed capacity level, this change will actually strengthen reliability. That is because PJM will be able to better count on a known pool of committed Capacity Resources to meet its resource adequacy needs as opposed to diminishing the incentive for such resources by providing Performance Payments to resources that PJM may not be able to rely upon and have no obligation to perform going forward.

As noted above, PJM maintains resource adequacy with capacity commitments procured through the RPM Auctions. It is those committed Capacity Resources that PJM should be able to rely upon to deliver energy during capacity emergencies. Diluting the eligible pool of bonus dollars by allocating a portion of it to uncommitted Capacity Resources, resources that do not qualify to be Capacity Resources and import transactions only diminishes the economic incentive for committed Capacity Resources to over-perform during Performance Assessment Intervals. Furthermore, there is simply no basis for simply assuming, as potential protesters might, that, absent Performance Payments, uncommitted resources would sit idly by during capacity emergencies. All resources that participate in the EAS markets have incentives to perform that are conveyed through the elevated EAS market clearing prices that occur during such periods (e.g., shortage pricing). Changing the eligibility for Performance Payments to focus on Generation Capacity Resources up to their committed level of installed capacity has the effect of re-allocating the capacity revenues from those resources that under-performed, given their accreditation, to those that over-performed during a Performance Assessment Interval.

The goal of shortage pricing is to elevate EAS prices, reflective of system conditions, during reserve shortages to incentivize the participation of all supply (resources and import transactions). To the extent the supply that did not take on a capacity commitment has inadequate incentives to perform during capacity emergencies, it should be viewed as indication of the need for further enhancements to the energy and reserve markets, not the need to shift capacity market revenues to resources that do did not take on a commitment and some that do not even qualify to do so. The product being provided by these uncommitted resources is the provision of EAS for which they should be compensated appropriately. That product, however, is not capacity. The capacity product qualifications and obligations including deliverability, recallability, energy and reserve market must-offer requirements and performance obligations all distinguish the capacity product from resources that participate purely in the EAS markets. Therefore, capacity revenues in the form of Performance Payments should remain within the pool of committed capacity resources.

3. *Limiting Performance Payments to Committed Generation Capacity Resources Also Addresses the Current Configuration of the Market Seller Offer Cap.*

The opportunity cost in the context of the capacity market represents the value that is foregone when a resource is committed as a Capacity Resource. In other words, it is equal to the revenue that a resource would forego by taking on a capacity obligation. Under the existing rules, opportunity cost in the form of Performance Payments are the potential revenues that an uncommitted resource could receive if it performs during a Performance Assessment Interval. However, neither the default Market Seller Offer Cap nor the unit-specific Market Seller Offer Cap provisions currently allow Capacity Market Sellers to include this the lost opportunity cost of taking on a capacity obligation in their capacity offers.[100]

PJM's proposal to limit Performance Payments to only committed Generation Capacity Resources not only increases the economic incentive for resources to be offered and clear the capacity auction, but also has the advantage of aligning the competitive offer of a potential Capacity Market Seller with the existing Market Seller Offer Cap rules. This is because by limiting Performance Payments to only those Generation Capacity Resources that have a capacity commitment up to their committed level of installed capacity, there is no lost opportunity cost because there are no foregone Performance Payments that uncommitted resources could collect in lieu of taking on a capacity commitment. Further, Generation Capacity Resources with a capacity commitment may also not cannot collect Performance Payments beyond their committed installed capacity level. As a result, with this change, incentives to become a well-performing capacity resource are increased and market power mitigation with respect to the Market Seller Offer Cap is simplified.

4. Exclusion of Demand Resources, Price Response Demand, and Energy Efficiency Resources from Performance Payments Is Appropriate.

Performance Payments are designed to reward resources for providing reliable capacity during Performance Assessment Intervals above the level they are expected to provide given their capacity commitment. While Demand Resources and Price Responsive Demand are eligible to be committed as Capacity Resources and receive compensation for

---

[100] While the existing Tariff contains a provision for opportunity cost, this cost is currently limited to "the documented price available to an existing generation resource in a market external to PJM." Tariff, Attachment DD, section 6.7(d)(ii). In other words, the only opportunity cost that is currently allowable are those that are foregone by not exporting out of PJM.

their capacity through the PJM Capacity Market, providing Performance Payments to Demand Resources is not consistent with PJM's proposal to change bonus eligibility to only committed Capacity Resources up to their committed installed capacity level. This new proposal for bonus eligibility excludes Demand Resources and Price Responsive Demand because their installed capacity levels are effectively based on the difference between Peak Load Contribution and their Firm Service Level. If these resources are fully committed and curtail below their Firm Service Levels, it would mean that they curtailed beyond their level of committed capacity. Rather than paying Bonus Performance to Demand Resources and Price Responsive Demand for curtailing beyond the Firm Service Level, Demand Resources and Price Responsive Demand with the capability to provide reductions beyond their Firm Service Level should be incentivized to offer those additional amounts as committed capacity.[101] This approach is consistent with the eligibility for Performance Payments for committed Generation Capacity Resources. That is, if a Generation Capacity Resource receives a partial commitment of its total unforced capacity, it would only be eligible for bonus based on the installed capacity equivalent of the unforced capacity commitment. Thus, any uncommitted portion of the Generation Capacity Resource would not be eligible for Performance Payments.

Additionally, Demand Resources and Price Responsive Demand are already ineligible for Performance Payments for performance above the Balancing Ratio under the existing rules.[102] That is because, for Demand Resources and Price Responsive Demand, the expected performance or the level against which performance is assessed for the

---

[101] Graf Aff. ¶ 61.

[102] Tariff, Attachment DD, section 10A(c).

purposes of Performance Assessment Intervals, is set at the installed capacity level (rather than unforced capacity times Balancing Ratio as it is for Generation Capacity Resources). The rationale for this design choice is that the commitment that Demand Resources take on is to reduce load to the Firm Service Level, rather than to provide output up to a certain level like Generation Capacity Resources. The expected resource adequacy value of such reduction to the Firm Service Level is assessed in the accreditation and risk analysis, where the load available to curtail is modeled as scaling proportionally with the level of system load. As Dr. Graf explains, "[t]he Balancing Ratio falling below one during a Performance Assessment Interval corresponds to an event when system load was below the total amount of capacity procured. Because Demand Resource load is modeled as scaling proportionally with system load, the load underlying the Demand Resource would be expected to naturally fall below such load's peak load contribution during the event."[103] In short, when Demand Resources or Price Responsive Demand curtail load to the Firm Service Level, the amount of curtailment achieved depends on what the load actually would have been on that day so the value actually provided is not equal to the unforced capacity level cleared in the auction, but rather is expected to equal unforced capacity times the Balancing Ratio. Thus, because the Demand Resource is providing value exactly equal to that which was assumed during accreditation, there is no over-performance to compensate.

Further, as witnessed during Winter Storm Elliott, there may be little relationship to the actual load reductions from Demand Resources and Price Responsive Demand during a Performance Assessment Interval. This is because many industrial and

---

[103] Graf Aff. ¶ 64.

commercial loads were already reduced or offline on the Friday evening before the Christmas weekend and on Christmas Eve. This resulted in Demand Resources appearing to have outperformed their committed capacity during the Winter Storm Elliott event even though the vast majority of load had already been reduced beyond the committed capacity level regardless of whether a Performance Assessment Interval was declared. The difficulty in separating out what could be labeled "over-performance" in response to a capacity emergency versus natural reductions for reasons unrelated to Performance Assessment Intervals is not limited to events occurring during low load periods such as holidays. Moreover, because Demand Resources are not required to provide metering data until months after a Performance Assessment Interval, PJM has little visibility on how Demand Resources and Price Responsive Demand are actually performing in real time during a capacity emergency. As a result, PJM operators are not able to see the immediate performance of Demand Resources and Price Responsive Demand in real time. This lag further makes it more difficult for the operators to count on a level of "over-performance" of these resources in real time.

Likewise, Energy Efficiency Resources should also not be eligible for Performance Payments because such resources do not provide specific real time reductions during a Performance Assessment Interval. In fact, under the existing rules, Energy Efficiency Resources actual performance is based on a comparison of their post-installation and measurement report, which is submitted 15 days *before* the Delivery Year even starts, and the committed MW quantity of the Energy Efficiency Resource.[104] Because the

[104] RAA, Schedule 6, section L.6.

accreditation of such resources is done outside of consideration of their ability to respond in real time to capacity emergencies, Energy Efficiency Resources should not be eligible for Performance Payments.

In sum, PJM's proposal to revise the eligibility of Performance Payments to the level of committed installed capacity, which ultimately precludes Demand Resources, Price Responsive Demand, and Energy Efficiency Resources from collecting such payments, is necessary to allow for the consistent treatment of all Capacity Resources with respect to such payments.

5. PJM Proposes Conforming Modifications to the Balancing Ratio Based on Updated Performance Payment Eligibility.

Consistent with these changes, PJM also proposes to amend the resources that are counted in the Balancing Ratio, which represents the proportion of total committed generation capacity resources that were needed in each interval, and thus represents the threshold between relative under-performance and over-performance of such committed resources.[105] Specifically, for purposes of the bonus eligibility, the Balancing Ratio numerator will be equal to the total committed Generation Capacity Resource's actual performance, capped at the committed installed capacity equivalent for each resource.[106] Additionally, the Balancing Ratio numerator will not include any net energy imports or Demand Resource, Price Responsive Demand, or Energy Efficiency Resources given the proposed revisions discussed above.[107]

[105] *See* proposed Tariff, Attachment DD, section 10A(c).

[106] *Id.*

[107] *Id.*

E. FRR Capacity Resources Should have the Same Financial Incentives to Perform During an Emergency as RPM-procured Capacity Resources.

PJM's capacity construct allows load-serving entities an alternative means of addressing their capacity obligations outside of RPM Auctions through a long-term commitment of resources. The alternative, known as the Fixed Resource Requirement Alternative ("FRR Alternative"), requires an FRR Entity to submit its preliminary FRR Capacity Plan at least one month prior to a Base Residual Auction. Currently, the performance incentives during a Performance Assessment Interval between RPM and the FRR Alternative can be misaligned. Accordingly, PJM is revising the FRR Alternative to remove that potential misalignment and provide "equitable treatment between FRR Entities and RPM participants and equivalent standards and methods for resource adequacy risk modeling and accreditation."[108]

Specifically, the existing RAA allows an FRR Entity to choose between financial or physical satisfaction of any Performance Shortfalls arising from the failure of any of the resources in an FRR Plan to perform during Performance Assessment Hours. Under the financial option, an FRR Entity may opt to be subject to the Non-Performance Assessment Charge.[109] In contrast, the physical option permits "FRR entities with under-performing resources the option to assign more capacity *in the future* rather than pay Non-Performance Charges for the underperformance."[110]

---

[108] Keech Aff. ¶ 34.

[109] *See* RAA, Schedule 8.1.C.

[110] Keech Aff. ¶ 37 (emphasis added).

The physical penalty rate is currently 0.00139 MW / Performance Assessment Interval [i.e., 0.5 MW / 30 PAHs / 12 intervals per hour].[111] This means that a hypothetical resource with 1,000 MW of shortfall summed across all Performance Assessment Intervals during Winter Storm Elliott would need to commit an additional 1.4 MW of capacity to their FRR plan for the delivery year following the event.[112] By contrast, if the FRR Entity for this resource instead chose the financial non-performance assessment option and was subject to the RTO Non-Performance Charge rate of $250.69/MW per five-minute interval, the resource would be assessed a charge of $250,690.[113]

Thus, as Mr. Adam Keech, PJM's Vice President of Market Design and Economics explains, the physical penalty option "defers the penalty's effects and can *severely* mute incentives to perform when the system needs it the most, especially when the FRR Entity has already excess supply not in its FRR Plan or can readily purchase it on the market at low cost."[114] Additionally, because the physical penalty option requires only that an FRR Entity assign additional Capacity Resources for one year, the resulting economic impact of the physical penalty option for not having sufficient resources during Performance Assessment Intervals is much lower than the financial option. In light of recent experience from Winter Storm Elliott, it is appropriate that FRR Entities are subject to the same Non-

[111] RAA, Schedule 8.1.G(2).

[112] *Winter Storm Elliott Event Analysis and Recommendation Report*, PJM Interconnection, L.L.C., 112 (July 17, 2023), https://pjm.com/-/media/library/reports-notices/special-reports/2023/20230717-winter-storm-elliott-event-analysis-and-recommendation-report.ashx.

[113] *Id*.

[114] Keech Aff. ¶ 37 (emphasis added).

Performance Charges for non-performance as any other committed Capacity Resource through the RPM Auctions.[115]

Given that there is no similar physical option that is available for RPM-committed Capacity Resources (they are assessed Non-Performance Charges for any underperformance), PJM proposes to phase out the physical option for FRR Entities by the 2025/2026 Delivery Year. The removal of the physical option will effectively expose FRR Entities to the same financial incentives for performance as Capacity Market Sellers of Capacity Resources with RPM commitments. This creates a uniform set of performance incentives for all committed Capacity Resources (whether through a commitment in RPM Auctions or through inclusion in an FRR Plan) during Performance Assessment Intervals.

Because FRR Entities generally plan satisfaction of capacity requirements on a longer, multi-year basis, PJM proposes a one-year grace period before the physical option is no longer available. Specifically, PJM proposes to provide FRR Entities the option of electing whether they are subject to the financial or physical penalty through the 2024/2025 Delivery Year. However, beginning with the 2025/2026 Delivery Year, FRR Entities will not have the option to select the physical non-performance penalty option,[116] and all FRR Entities will be subject to only the Non-Performance Charges.[117]

---

[115] Keech Aff. ¶ 37.

[116] *See* Tariff, Attachment DD, section 10A (as described by proposed RAA, Schedule 8.1.G.1).

[117] *See* proposed RAA, Schedule 8.1.C.

III. PJM PROPOSES TO ADOPT A FORWARD NET ENERGY AND ANCILLARY SERVICE REVENUE FOR CALCULATING MITIGATED OFFERS UNDER THE MARKET SELLER OFFER CAP AND MINIMUM OFFER PRICE RULE

Through this filing, PJM is also proposing to adopt a forward-looking approach to determine the net EAS, in the context of the Market Seller Offer Cap and the MOPR, that a resource can reasonably be expected to earn in PJM participating in the energy and ancillary service markets. PJM proposes the same approach for determining the net EAS for the Market Seller Offer Cap and the MOPR (with minor updates to certain values) as the Commission has twice accepted for determine the net EAS used in the VRR Curve.[118] This forward looking net EAS approach was only removed from the Tariff because the Commission found, on voluntary remand from the United States Court of Appeals for the District of Columbia Circuit,[119] that there was insufficient evidence to support the Commission's directive to switch the EAS offset from historical to forward-looking based on the record in the reserve price formation docket.[120] However, in that order, the Commission went out of its way to clarify that it was "not finding that a forward-looking E&AS offset is unjust and unreasonable or that PJM cannot propose a forward-looking E&AS offset."[121]

---

[118] *See PJM Interconnection, L.L.C.*, 182 FERC ¶ 61,073 (2023); *PJM Interconnection, L.L.C.*, 173 FERC ¶ 61,134 (2020).

[119] *Am. Mun. Power, Inc. v. FERC*, No. 20-1372 (D.C. Cir. Aug. 23, 2021) (order granting unopposed motion for voluntary remand). The consolidated appeals involve challenges to *PJM Interconnection, L.L.C.*, 171 FERC ¶ 61,153, *order on reh'g*, 173 FERC ¶ 61,123 (2020); and *PJM Interconnection, L.L.C.*, 173 FERC ¶ 61,134 (2020), *order on reh'g*, 174 FERC ¶ 61,180 (2021).

[120] *PJM Interconnection, L.L.C.*, 177 FERC ¶ 61,209, at P 46 (2021), *order on reh'g*, 180 FERC ¶ 61,051 (2022).

[121] *Id.*

As a result, PJM now proposes to replace the existing tariff provisions as it relates to the net EAS calculation in the Market Seller Offer Cap and the MOPR,[122] which currently calculate net EAS revenues based on a historical rolling average. In its place, PJM proposes to utilize a forward-looking net EAS methodology that will instead use forward-looking electricity and fuel data.[123] As part of this proposal, PJM will also employ the same Projected EAS Dispatch model for the determination of EAS revenues for dispatchable resources that the Commission recently approved as part of PJM's 2022 quadrennial review.[124] In addition, all generation resource types will continue to be credited with revenues for providing reactive service.

In short, and as further detailed in Dr. Graf's affidavit, PJM proposes a common forward-looking EAS offset estimating method, with three main components,[125] which is entirely consistent with PJM's prior filings to adopt a forward net EAS offset and have previously been accepted by the Commission: [126]

- Using publicly available energy and fuel price data from liquid forward markets for the same timeframe as the Delivery Year at issue, applying locational adjustments and hourly (for energy) and daily (for fuel) price shaping using commercially reasonable and customary methods;

---

[122] Proposed Tariff, Attachment DD, section 5.14(h-2) and Proposed Tariff, Attachment DD, section 6.8(d-1).

[123] Given that PJM is proposing to implement the forward-looking EAS offset commencing with the Base Residual Auction for the 2025/2026 Delivery Year, the Tariff revisions included in this filing make clear that the existing historical EAS offset approach will remain in place for the Incremental Auctions for the 2024/2025 Delivery Year and the forward-looking EAS offset will apply for the 2025/2026 Delivery Year and subsequent Delivery Years. The revisions updating the determination of the Market Seller Offer Cap to a forward-looking approach also make clear that the new approach will apply for the 2025/2026 Delivery Year and subsequent Delivery Years. *See* proposed Tariff, Attachment DD, section 6.8(d-1).

[124] *See PJM Interconnection, L.L.C.*, 182 FERC ¶ 61,073.

[125] *See* Graf Aff. ¶¶ 106-158.

[126] *PJM Interconnection, L.L.C.*, 173 FERC ¶ 61,134.

- Running resource revenue models with the forward-based energy and fuel prices, and key resource characteristics and parameters, as inputs, using two basic model types:
    - A Projected EAS Dispatch Model for dispatchable resources; or
    - An assumed output model, for non-dispatchable resources, applied to the forward energy prices referenced above; and
- Estimating market-based ancillary service revenues using ancillary services prices in co-optimized dispatch models, plus cost-based reactive service revenues.

PJM proposes to adapt and apply that general method to estimate:

- The EAS offsets for resource-type default MOPR Offer Floor Prices, using resource-type-appropriate fuel and assumed output or Projected EAS Dispatch models;
- EAS offset determination methodologies for resource-specific exceptions to the MOPR Floor Offer Prices, with certain defined flexibility, and certain defined limitations; and
- EAS offset determination methodologies for resource-specific Market Seller Offer Price Caps.

These proposed updates will align the use of a forward net EAS offset for the Market Seller Offer Cap and MOPR calculations with those that are already approved for determining the net EAS of the Reference Resource used in setting the VRR Curve.[127] Further, the Commission has already found just and reasonable application of this very approach in the context of the MOPR.[128]

Along with these revisions, PJM proposes reasonable deadlines for the Market Monitor to calculate Projected PJM Market Revenues.[129] Currently, the Tariff requires that the Market Monitor calculate Projected PJM Market Revenues no later than ninety days

---

[127] *See PJM Interconnection, L.L.C.*, 182 FERC ¶ 61,073.

[128] *See PJM Interconnection, L.L.C.*, 173 FERC ¶ 61,134.

[129] Proposed Tariff, Attachment M-Appendix, section II.E.

before a relevant RPM Auction. However, given that unit-specific Market Seller Offer Cap and unit-specific MOPR requests are due 120 days before each RPM Auction, Capacity Market Sellers would not know what the applicable default Market Seller Offer Cap or MOPR would be since the Tariff only provide gross CONE or gross ACR values, which need to be offset by the Projected PJM Market Revenues that the Market Monitor calculates. Therefore, PJM proposes that the Market Monitor provide a preliminary Projected PJM Market Revenue by 150 days before each RPM Auction and a final Projected PJM Market Revenue value by 120 days before each RPM Auction. This approach provides Capacity Market Sellers an indication of what the default Market Seller Offer Cap or MOPR floor price for their resource will be sufficiently in advance of the unit-specific deadline so they can prepare for a potential request for a unit-specific offer cap or MOPR value. Setting the deadline for the Market Monitor to provide final Projected PJM Market Revenues at 125 days prior to an auction will provide Capacity Market Sellers with certainty regarding the applicable default values prior to their finalizing a decision on whether to submit a request for a unit-specific offer cap or MOPR value.

IV. ALL SUBSTANTIVE CHANGES PROPOSED IN THIS FILING ARE TO BE EFFECTIVE STARTING WITH THE 2025/2026 DELIVERY YEAR AND WILL NOT DISTURB THE 2024/2025 DELIVERY YEAR

As discussed, PJM is proposing to implement all the changes proposed in this filing starting with the 2025/2026 Delivery Year and for all subsequent Delivery Years. The current-effective Tariff capacity market rules will all remain in effect through the end of the 2024/2025 Delivery Year, and will govern issues related to Delivery Years prior to the 2025/2026 Delivery Year, including the Third Incremental Auction conducted for the 2024/2025 Delivery Year. The Tariff revisions PJM is proposing clearly specify this delineation and state that the changes proposed in this filing apply only beginning with the 2025/2026 Delivery Year and all subsequent Delivery Years.

V. PJM PROPOSES CLERICAL, MINISTERIAL, AND NON-SUBSTANTIVE REVISIONS TO THE TARIFF IN THIS FILING

Finally, as part of this filing, PJM is proposing limited clerical, ministerial, and non-substantive revisions to the sections of the Tariff that are impacted by this filing. These revisions are generally limited to removing references to capacity market products (such as Base Capacity Resources) or capacity market rules that have been sunset and are no longer applicable. Other minor amendments include properly referencing capitalized and defined terms in the sections of the Tariff that are impacted by the broader substantive changes proposed in this filing.[130] In addition, the redlines also reflect the Commission's previously accepted language but is not reflected in the current version of the Tariff given overlapping filings to the same section of the Tariff. For instance, the Commission previously accepted the removal of language in Tariff, Attachment M-Appendix, section II.E.3 that removed the alternative Market Seller Offer Cap provision in Docket No. ER22-2886-000,[131] but this deletion from the Tariff was not reflected in a separate filing that was submitted (and also accepted[132]) in Docket No. ER22-2342-000. Thus, this filing also proposes to rectify such overlapping tariff provisions.

---

[130] *See* Tariff, Attachment DD, section 4.5; Tariff, Attachment DD, sections 5.14(c)(3) & (8), f(i-ii); Tariff, Attachment DD, section 6.7; Tariff, Attachment DD, section 6.8(a); Tariff, Attachment DD, sections 10A(a), (c), (e), (f), (h); RAA, Schedule 8.1.C(1); RAA, Schedule 8.1.G(2).

[131] *PJM Interconnection, L.L.C.*, 181 FERC ¶ 61,150 (2022).

[132] *PJM Interconnection, L.L.C.*, Letter Order, Docket No. ER22-2342-000 (Aug. 19, 2022).

VI. STAKEHOLDER PROCESS

Recognizing the need for reforming PJM's capacity rules, in October 2021, PJM and its stakeholders established the RASTF, and began extensively examining a number of issues presented in this filing and the companion filing. The RASTF held 30 meetings between October 2021 and March 2023 alone. Complementing the RASTF, PJM undertook its own review of near- and long-term resource adequacy challenges, and published four papers.

In February 2023, the PJM Board of Directors ("Board") initiated a Critical Issue Fast Path ("CIFP") accelerated stakeholder process to further examine these issues. The Board recognized that "[w]hile PJM currently has a healthy reserve margin, Winter Storm Elliott demonstrated that PJM is not immune to reliability challenges as the system was stressed, even with a reserve margin in excess of the target and a lower level of renewable penetration than other regions."[133] The Board also appreciated that the "the healthy reserve margins [the PJM Region] enjoy[s] now cannot be taken for granted into the future," and directed PJM and its stakeholders to identify "near-term changes to the Reliability Pricing Model (RPM) [] necessary to ensure that PJM can maintain resource adequacy into the future."[134]

On August 23, 2023, at the final meeting of the CIFP and the PJM Members Committee meeting, PJM, the PJM Market Monitor, and numerous stakeholders presented and discussed proposals in a meeting with members of the Board. Over the next month,

---

[133] Letter from Mark Takahashi, Chair, PJM Board of Managers, to PJM Interconnection, L.L.C. Stakeholders (Feb. 24, 2023) (https://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/20230224-board-letter-re-initiation-of-the-critical-issue-fast-path-process-to-address-resource-adequacy-issues.ashx).

[134] *Id.*

the Board deliberated and determined that the reforms proposed in this filing would provide near-term changes to PJM's capacity construct to maintain resource adequacy at reasonable costs during the energy transition. Thereafter, on September 27, 2023, the Board directed PJM to file a suite of capacity market reforms.

Subsequently, on October 5, 2023, PJM reviewed draft revisions to the Tariff and RAA to implement the reforms proposed in this section 205 filing and the companion section 205 filing. In total, over the course of five months, PJM and its stakeholder held 16 CIFP stakeholder meetings in which various capacity market reforms were discussed and analyzed to achieve this goal. Before the CIPF process, PJM held and additional 47 stakeholder meetings since October 2021 to pursue holistic reforms to PJM's capacity market.

VII. PROPOSED EFFECTIVE DATES

PJM proposes an effective date of December 12, 2023 for the proposed Tariff and RAA revisions described herein. PJM requests that the Commission issue an order on this filing by December 12, 2023. Timely Commission action is needed on this filing given that the Base Residual Auction associated with the 2025/2026 Delivery Year is scheduled to commence in June 1, 2024,[135] with many pre-auction deadlines associated with this upcoming in mid-January, 2024.[136] Thus, acceptance of this filing by the requested effective date is necessary to provide for an orderly conduct of the next Base Residual Auction.

---

[135] Tariff, Attachment DD, section 5.6(a).

[136] *See RPM Auction Schedule*, PJM Interconnection, L.L.C. (Sept. 25, 2023), https://pjm.com/-/media/markets-ops/rpm/rpm-auction-info/rpm-auction-schedule.ashx.

VIII. DESCRIPTION OF SUBMITTAL

This filing consists of the following:

1. This transmittal letter;

2. Attachment A – Revisions to the Tariff and RAA in redline format;

3. Attachment B – Revisions to the Tariff and RAA in clean format;

4. Attachment C – Affidavit of Adam Keech on Behalf of PJM Interconnection, L.L.C.; and

5. Attachment D - Affidavit of Dr. Walter Graf on Behalf of PJM Interconnection, L.L.C.

IX. CORRESPONDENCE

The following individuals are designated for inclusion on the official service list in this proceeding and for receipt of any communications regarding this filing:

Chenchao Lu
Associate General Counsel
PJM Interconnection, L.L.C.
2750 Monroe Boulevard
Audubon, Pennsylvania 19403
(610) 666-2255
chenchao.lu@pjm.com

Craig Glazer
Vice President - Federal Government Policy
PJM Interconnection, L.L.C.
1200 G Street, N.W, Suite 600
Washington, D.C. 20005
(202) 423-4743
craig.glazer@pjm.com

X. SERVICE

PJM has served a copy of this filing on all PJM Members and on all state utility regulatory commissions in the PJM Region by posting this filing electronically. In accordance with the Commission's regulations,[137] PJM will post a copy of this filing to the FERC filings section of its internet site, located at the following link: https://www.pjm.com/library/filing-order.aspx with a specific link to the newly-filed

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

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[138] 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 available through the referenced link within 24 hours of the filing. Also, a copy of this filing will be available on the FERC's eLibrary website located at the following link: https://elibrary.ferc.gov/eLibrary/search in accordance with the Commission's regulations and Order No. 714.

XI. CONCLUSION

Based on the foregoing, PJM requests that the Commission accept the enclosed Tariff and RAA revisions, effective December 12, 2023. As noted, *supra*, this set of proposed revisions complements the enhancements to risk modeling, accreditation (including application to FRR resources), testing, and stop-loss that are being proposed in a concurrent but separate filing. The proposed changes in this filing represent a set of reforms that will better align the Market Seller Offer Cap with the risks of committing a Capacity Resource, while also aligning enhancing certain capacity performance rules.[139]

As noted, PJM's proposed revisions in this filing are just and reasonable on a standalone basis, and PJM's proposed revisions in PJM's concurrent filing are also just and reasonable on a standalone basis. However, the combined revisions of the two section 205 filings together would provide greater synergies and are preferable as a just and reasonable

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

[139] As noted above, PJM consents to severing the proposed revisions regarding the eligibility of Performance Payments from the rest of this filing if deemed necessary.

capacity construct for the PJM Region. To that end, PJM urges that the Commission accept both sets of filings concurrently so that the reforms set forth in this filing align with the changes proposed in PJM's concurrent filing on risk modeling and accreditation. This will appropriately reflect the synergies between compensation for risk and bonus eligibility with the new testing requirements and accreditation rules that will apply to Capacity Resources that are committed in PJM's capacity market. Acceptance of both files concurrently and without delay will allow for an orderly implementation of these enhancements beginning with the upcoming Base Residual Auction associated with the 2025/2026 Delivery Year.

Respectfully submitted,

/s/ *Chenchao Lu*

Craig Glazer
Vice President–Federal Government Policy
PJM Interconnection, L.L.C.
1200 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 423-4743 (phone)
(202) 393-7741 (fax)
Craig.Glazer@pjm.com

Chenchao Lu
Associate General Counsel
PJM Interconnection, L.L.C.
2750 Monroe Blvd.
Audubon, PA 19403
(610) 666-2255 (phone)
(610) 666-8211 (fax)
Chenchao.Lu@pjm.com

Attachment A

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)

ATTACHMENT M – APPENDIX

I. CONFIDENTIALITY OF DATA AND INFORMATION

A. Party Access:

1. No Member shall have a right hereunder to receive or review any documents, data or other information of another Member, including documents, data or other information provided to the Market Monitoring Unit, to the extent such documents, data or information have been designated as confidential pursuant to the procedures adopted by the Market Monitoring Unit or to the extent that they have been designated as confidential by such other Member; provided, however, a Member may receive and review any composite documents, data and other information that may be developed based on such confidential documents, data or information if the composite does not disclose any individual Member's confidential data or information.

2. Except as may be provided in this Appendix, the Plan, the PJM Operating Agreement or in the PJM Tariff, the Market Monitoring Unit shall not disclose to PJM Members or to third parties, any documents, data, or other information of a Member or entity applying for Membership, to the extent such documents, data, or other information has been designated confidential pursuant to the procedures adopted by the Market Monitoring Unit or by such Member or entity applying for membership; provided that nothing contained herein shall prohibit the Market Monitoring Unit from providing any such confidential information to its agents, representatives, or contractors to the extent that such person or entity is bound by an obligation to maintain such confidentiality.

The Market Monitoring Unit, its designated agents, representatives, and contractors shall maintain as confidential the electronic tag ("e-Tag") data of an e-Tag Author or Balancing Authority (defined as those terms are used in FERC Order No. 771) to the same extent as Member data under this section I. Nothing contained herein shall prohibit the Market Monitoring Unit from sharing with the market monitor of another Regional Transmission Organization ("RTO"), Independent System Operator ("ISO"), upon their request, the e-Tags of an e-Tag Author or Balancing Authority for intra-PJM Region transactions and interchange transactions scheduled to flow into, out of or through the PJM Region, to the extent such market monitor has requested such information as part of its investigation of possible market violations or market design flaws, and to the extent that such market monitor is bound by a tariff provision requiring that the e-Tag data be maintained as confidential, or in the absence of a tariff requirement governing confidentiality, a written agreement with the Market Monitoring Unit consistent with FERC Order No. 771, and any clarifying orders and implementing regulations.

The Market Monitoring Unit shall collect and use confidential information only in connection with its authority under this Appendix, the Plan, the PJM Operating Agreement or in the PJM Tariff and the retention of such information shall be in accordance with the Office of the Interconnection's data retention policies.

3. Nothing contained herein shall prevent the Market Monitoring Unit from releasing a Member's confidential data or information to a third party provided that the Member has delivered to the Market Monitoring Unit specific, written authorization for such release setting forth the data

or information to be released, to whom such release is authorized, and the period of time for which such release shall be authorized. The Market Monitoring Unit shall limit the release of a Member's confidential data or information to that specific authorization received from the Member. Nothing herein shall prohibit a Member from withdrawing such authorization upon written notice to the Market Monitoring Unit, who shall cease such release as soon as practicable after receipt of such withdrawal notice.

4. Reciprocal provisions to this section I hereof, delineating the confidentiality requirements of the Office of the Interconnection and PJM members, are set forth in Operating Agreement, section 18.17.

B. <u>Required Disclosure</u>:

1. Notwithstanding anything in the foregoing section to the contrary, and subject to the provisions of section I.C below, if the Market Monitoring Unit is required by applicable law, order, or in the course of administrative or judicial proceedings, to disclose to third parties, information that is otherwise required to be maintained in confidence pursuant to the PJM Tariff, PJM Operating Agreement, Tariff, Attachment M or this Appendix, the Market Monitoring Unit may make disclosure of such information; provided, however, that as soon as the Market Monitoring Unit learns of the disclosure requirement and prior to making disclosure, the Market Monitoring Unit shall notify the affected Member or Members of the requirement and the terms thereof and the affected Member or Members may direct, at their sole discretion and cost, any challenge to or defense against the disclosure requirement. The Market Monitoring Unit shall cooperate with such affected Members to the maximum extent practicable to minimize the disclosure of the information consistent with applicable law. The Market Monitoring Unit shall cooperate with the affected Members to obtain proprietary or confidential treatment of such information by the person to whom such information is disclosed prior to any such disclosure.

2. Nothing in this section I shall prohibit or otherwise limit the Market Monitoring Unit's use of information covered herein if such information was: (i) previously known to the Market Monitoring Unit without an obligation of confidentiality; (ii) independently developed by or for the Office of the Interconnection and/or the Market Monitoring Unit using non-confidential information; (iii) acquired by the Office of the Interconnection and/or the Market Monitoring Unit from a third party which is not, to the Office of the Interconnection's or Market Monitoring Unit's knowledge, under an obligation of confidence with respect to such information; (iv) which is or becomes publicly available other than through a manner inconsistent with this section I.

3. The Market Monitoring Unit shall impose on any contractors retained to provide technical support or otherwise to assist with the implementation of the Plan or this Appendix a contractual duty of confidentiality consistent with the Plan or this Appendix. A Member shall not be obligated to provide confidential or proprietary information to any contractor that does not assume such a duty of confidentiality, and the Market Monitoring Unit shall not provide any such information to any such contractor without the express written permission of the Member providing the information.

C. <u>Disclosure to FERC and CFTC</u>:

1. Notwithstanding anything in this section I to the contrary, if the FERC, the Commodity Futures Trading Commission ("CFTC") or the staff of those commissions, during the course of an investigation or otherwise, requests information from the Market Monitoring Unit that is otherwise required to be maintained in confidence pursuant to the PJM Tariff, the PJM Operating Agreement, the Plan or this Appendix, the Market Monitoring Unit shall provide the requested information to the FERC, CFTC or their staff, within the time provided for in the request for information. In providing the information to the FERC or its staff, the Market Monitoring Unit may request, consistent with 18 C.F.R. §§ 1b.20 and 388.112, or to the CFTC or its staff, the Market Monitoring Unit may request, consistent with 17 C.F.R. §§ 11.3 and 145.9, that the information be treated as confidential and non-public by the respective commission and its staff and that the information be withheld from public disclosure. The Market Monitoring Unit shall promptly notify any affected Member(s) if the Market Monitoring Unit receives from the FERC, CFTC or their staff, written notice that the commission has decided to release publicly or has asked for comment on whether such commission should release publicly, confidential information previously provided to a commission Market Monitoring Unit.

2. The foregoing section I.C.1 shall not apply to requests for production of information under Subpart D of the FERC's Rules of Practice and Procedure (18 CFR Part 385) in proceedings before FERC and its administrative law judges. In all such proceedings, the Office of the Interconnection and/or the Market Monitoring Unit shall follow the procedures in section I.B.

D. <u>Disclosure to Authorized Commissions</u>:

1. Notwithstanding anything in this section I to the contrary, the Market Monitoring Unit shall disclose confidential information, otherwise required to be maintained in confidence pursuant to the PJM Tariff, the PJM Operating Agreement, the Plan or this Appendix, to an Authorized Commission under the following conditions:

(i) The Authorized Commission has provided the FERC with a properly executed Certification in the form attached to the PJM Operating Agreement as Operating Agreement, Schedule 10A. Upon receipt of the Authorized Commission's Certification, the FERC shall provide public notice of the Authorized Commission's filing pursuant to 18 C.F.R. § 385.2009. If any interested party disputes the accuracy and adequacy of the representations contained in the Authorized Commission's Certification, that party may file a protest with the FERC within 14 days of the date of such notice, pursuant to 18 C.F.R. § 385.211. The Authorized Commission may file a response to any such protest within seven days. Each party shall bear its own costs in connection with such a protest proceeding. If there are material changes in law that affect the accuracy and adequacy of the representations in the Certification filed with the FERC, the Authorized Commission shall, within thirty (30) days, submit an amended Certification identifying such changes. Any such amended Certification shall be subject to the same procedures for comment and review by the FERC as set forth above in this paragraph.

(ii) Neither the Office of the Interconnection nor the Market Monitoring Unit may disclose data to an Authorized Commission during the FERC's consideration of the Certification and any filed protests. If the FERC does not act upon an Authorized Commission's Certification within 90 days of the date of filing, the Certification shall be deemed approved and the Authorized Commission shall be permitted to receive confidential information pursuant to this Section I. In the event that an interested party protests the Authorized Commission's Certification and the FERC approves the Certification, that party may not challenge any Information Request made by the Authorized Commission on the grounds that the Authorized Commission is unable to protect the confidentiality of the information requested, in the absence of a showing of changed circumstances.

(iii) Any confidential information provided to an Authorized Commission pursuant to this section I shall not be further disclosed by the recipient Authorized Commission except by order of the FERC.

(iv) The Market Monitoring Unit shall be expressly entitled to rely upon such Authorized Commission Certifications in providing confidential information to the Authorized Commission, and shall in no event be liable, or subject to damages or claims of any kind or nature hereunder, due to the ineffectiveness or inaccuracy of such Authorized Commission Certifications.

(v) The Authorized Commission may provide confidential information obtained from the Market Monitoring Unit to such of its employees, attorneys and contractors as needed to examine or handle that information in the course and scope of their work on behalf of the Authorized Commission, provided that (a) the Authorized Commission has internal procedures in place, pursuant to the Certification, to ensure that each person receiving such information agrees to protect the confidentiality of such information (such employees, attorneys or contractors to be defined hereinafter as "Authorized Persons"); (b) the Authorized Commission provides, pursuant to the Certification, a list of such Authorized Persons to the Office of the Interconnection and the Market Monitoring Unit and updates such list, as necessary, every ninety (90) days; and (c) any third-party contractors provided access to confidential information sign a nondisclosure agreement in the form attached to the PJM Operating Agreement as Operating Agreement, Schedule 10 before being provided access to any such confidential information.

2. The Market Monitoring Unit may, in the course of discussions with an Authorized Person, orally disclose information otherwise required to be maintained in confidence, without the need for a prior Information Request. Such oral disclosures shall provide enough information to enable the Authorized Person or the Authorized Commission with which that Authorized Person is associated to determine whether additional Information Requests are appropriate. The Market Monitoring Unit will not make any written or electronic disclosures of confidential information to the Authorized Person pursuant to this section I.D.2. In any such discussions, the Market Monitoring Unit shall ensure that the individual or individuals receiving such confidential information are Authorized Persons as defined herein, orally designate confidential information that is disclosed, and refrain from identifying any specific Affected Member whose information is disclosed. The Market Monitoring Unit shall also be authorized to assist Authorized Persons in interpreting confidential information that is disclosed. The Market Monitoring Unit shall provide any Affected Member with oral notice of any oral disclosure immediately, but not later than one (1) Business Day after the oral disclosure. Such oral notice to the Affected Member shall include the substance of the oral disclosure, but shall not reveal any confidential information of any other Member and must be received by the Affected Member before the name of the Affected Member

is released to the Authorized Person; provided however, disclosure of the identity of the Affected Party must be made to the Authorized Commission with which the Authorized Person is associated within two (2) Business Days of the initial oral disclosure.

3. As regards Information Requests:

(i) Information Requests to the Office of the Interconnection and/or Market Monitoring Unit by an Authorized Commission shall be in writing, which shall include electronic communications, addressed to the Market Monitoring Unit, and shall: (a) describe the information sought in sufficient detail to allow a response to the Information Request; (b) provide a general description of the purpose of the Information Request; (c) state the time period for which confidential information is requested; and (d) re-affirm that only Authorized Persons shall have access to the confidential information requested. The Market Monitoring Unit shall provide an Affected Member with written notice, which shall include electronic communication, of an Information Request by an Authorized Commission as soon as possible, but not later than two (2) Business Days after the receipt of the Information Request.

(ii) Subject to the provisions of section I.D.3(iii) below, the Market Monitoring Unit shall supply confidential information to the Authorized Commission in response to any Information Request within five (5) Business Days of the receipt of the Information Request, to the extent that the requested confidential information can be made available within such period; provided however, that in no event shall confidential information be released prior to the end of the fourth (4th) Business Day without the express consent of the Affected Member. To the extent that the Market Monitoring Unit cannot reasonably prepare and deliver the requested confidential information within such five (5) day period, it shall, within such period, provide the Authorized Commission with a written schedule for the provision of such remaining confidential information. Upon providing confidential information to the Authorized Commission, the Market Monitoring Unit shall either provide a copy of the confidential information to the Affected Member(s), or provide a listing of the confidential information disclosed; provided, however, that the Market Monitoring Unit shall not reveal any Member's confidential information to any other Member.

(iii) Notwithstanding section I.D.3(ii), above, should the Office of the Interconnection, the Market Monitoring Unit or an Affected Member object to an Information Request or any portion thereof, any of them may, within four (4) Business Days following the Market Monitoring Unit's receipt of the Information Request, request, in writing, a conference with the Authorized Commission to resolve differences concerning the scope or timing of the Information Request; provided, however, nothing herein shall require the Authorized Commission to participate in any conference. Any party to the conference may seek assistance from FERC staff in resolution of the dispute or terminate the conference process at any time. Should such conference be refused or terminated by any participant or should such conference not resolve the dispute, then the Office of the Interconnection, Market Monitoring Unit, or the Affected Member may file a complaint with the FERC pursuant to Rule 206 objecting to the Information Request within ten (10) Business Days following receipt of written notice from any conference participant terminating such conference. Any complaints filed at the FERC objecting to a particular Information Request shall be designated by the party as a "fast track" complaint and each party shall bear its own costs in connection with such FERC proceeding. The grounds for such a complaint shall be limited to the following: (a) the Authorized Commission is no longer able to preserve the confidentiality of the requested information due to changed circumstances relating to the Authorized Commission's ability to protect confidential information arising since the filing of or rejection of a protest directed to the Authorized Commission's Certification; (b) complying with the Information Request would be unduly burdensome to the complainant, and the complainant has made a good faith effort to negotiate limitations in the scope of the requested information; or (c) other exceptional circumstances exist such that complying with the Information Request would result in harm to the complainant. There shall be a presumption that "exceptional circumstances," as used in the prior sentence, does not include circumstances in which an Authorized Commission has requested wholesale market data (or Market Monitoring Unit workpapers that support or explain conclusions or analyses) generated in the ordinary course and scope of the operations of the Market Monitoring Unit. There shall be a presumption that circumstances in which an Authorized Commission has requested personnel files, internal emails and internal company memos, analyses and related work product constitute "exceptional circumstances" as used in the prior sentence. If no complaint challenging the Information Request is filed within the ten (10) day period defined above, the Office of the Interconnection and/or Market Monitoring Unit shall utilize its best efforts to respond to the Information Request promptly. If a complaint is filed, and the Commission does not act on that complaint within ninety (90) days, the complaint shall be deemed denied and the Market Monitoring Unit shall use its best efforts to respond to the Information Request promptly.

(iv) Any Authorized Commission may initiate appropriate legal action at the FERC within ten (10) Business Days following receipt of information designated as "Confidential," challenging such designation. Any complaints filed at FERC objecting to the designation of information as "Confidential" shall be designated by the party as a "fast track" complaint and each party shall bear its own costs in connection with such FERC proceeding. The party filing such a complaint shall be required to prove that the material disclosed does not merit "Confidential" status because it is publicly available from other sources or contains no trade secret or other sensitive commercial information (with "publicly available" not being deemed to include unauthorized disclosures of otherwise confidential data).

4. In the event of any breach of confidentiality of information disclosed pursuant to an Information Request by an Authorized Commission or Authorized Person:

(i) The Authorized Commission or Authorized Person shall promptly notify the Market Monitoring Unit, who shall, in turn, promptly notify any Affected Member of any inadvertent or intentional release, or possible release, of confidential information provided pursuant to this section I.

(ii) The Office Market Monitoring Unit shall terminate the right of such Authorized Commission to receive confidential information under this section I upon written notice to such Authorized Commission unless: (i) there was no harm or damage suffered by the Affected Member; or (ii) similar good cause is shown. Any appeal of the Market Monitoring Unit's actions under this section I shall be to Commission. An Authorized Commission shall be entitled to reestablish its certification as set forth in section I.D.1 by submitting a filing with the Commission showing that it has taken appropriate corrective action. If the Commission does not act upon an Authorized Commission's recertification filing with sixty (60) days of the date of the filing, the recertification shall be deemed approved and the Authorized Commission shall be permitted to receive confidential information pursuant to this section.

(iii) The Office of the Interconnection, the Market Monitoring Unit, and/or the Affected Member shall have the right to seek and obtain at least the following types of relief: (a) an order from the FERC requiring any breach to cease and preventing any future breaches; (b) temporary, preliminary, and/or permanent injunctive relief with respect to any breach; and (c) the immediate return of all confidential information to the Market Monitoring Unit.

(iv) No Authorized Person or Authorized Commission shall have responsibility or liability whatsoever under this section for any and all liabilities, losses, damages, demands, fines, monetary judgments, penalties, costs and expenses caused by, resulting from, or arising out of or in connection with the release of confidential information to persons not authorized to receive it, provided that such Authorized Person is an agent, servant, employee or member of an Authorized Commission at the time of such unauthorized release. Nothing in this section I.D.4(iv) is intended to limit the liability of any person who is not an agent, servant, employee or member of an Authorized Commission at the time of such unauthorized release for any and all economic losses, damages, demands, fines, monetary judgments, penalties, costs and expenses caused by, resulting from, or arising out of or in connection with such unauthorized release.

(v) Any dispute or conflict requesting the relief in section I.D.4(ii) or I.D.4(iii)(a) above, shall be submitted to the FERC for hearing and resolution. Any dispute or conflict requesting the relief in section I.D.4(iii)(c) above may be submitted to FERC or any court of competent jurisdiction for hearing and resolution.

E. [Reserved]

II. DEVELOPMENT OF INPUTS FOR PROSPECTIVE MITIGATION

A. Offer Price Caps:

1. The Market Monitor or his designee shall advise the Office of the Interconnection whether it believes that the cost references, methods and rules included in the Cost Development Guidelines are accurate and appropriate, as specified in the PJM Manuals.

2. The Market Monitoring Unit shall review the incremental costs (defined in Operating Agreement, Schedule 1, section 6.4.2and the parallel provisions of Tariff, Attachment K-Appendix, section 6.4.2) included in the Offer Price Cap of a generating unit in order to ensure that the Market Seller has correctly applied the Cost Development Guidelines, including its PJM-approved Fuel Cost Policy, and that the level of the Offer Price Cap is otherwise acceptable. The Market Monitoring Unit shall inform PJM if it believes a Market Seller has submitted a cost-based offer that is not compliant with these criteria and whether it recommends that PJM assess the applicable penalty therefor, pursuant to Operating Agreement, Schedule 2.

3. On or before the 21st day of each month, the Market Monitoring Unit shall calculate in accordance with the applicable criteria whether each generating unit with an offer cap calculated

under Operating Agreement, Schedule 1, section 6.4.2 and the parallel provisions of Tariff, Attachment K-Appendix, section 6.4.2 is eligible to include an adder based on Frequently Mitigated Unit or Associated Unit status, and shall issue a written notice of the applicable adder, with a copy to the Office of the Interconnection, to the Market Seller for each unit that meets the criteria for Frequently Mitigated Unit or Associated Unit status.

4. Notwithstanding the number of jointly pivotal suppliers in any hour, if the Market Monitoring Unit determines that a reasonable level of competition will not exist based on an evaluation of all facts and circumstances, it may propose to the Commission the removal of offer-capping suspensions otherwise authorized by Operating Agreement, Schedule 1, section 6.4 and the parallel provisions of Tariff, Attachment K-Appendix, section 6.4. Such proposals shall take effect upon Commission acceptance of the Market Monitoring Unit's filing.

5. The Market Monitoring Unit shall review all Fuel Cost Policies submitted by Market Sellers for market power concerns. The Market Monitoring Unit shall communicate its determination regarding these criteria to PJM and the Market Seller pursuant to the process further described in PJM Manual 15.

B. <u>Minimum Generator Operating Parameters</u>:

1. For the 2014/2015 through 2017/2018 Delivery Years, the Market Monitoring Unit shall provide to the Office of the Interconnection a table of default unit class specific parameter limits to be known as the "Parameter Limited Schedule Matrix" to be included in Operating Agreement, Schedule 1, section 6.6(c) and the parallel provisions of Tariff, Attachment K-Appendix, section 6.6(c). The Parameter Limited Schedule Matrix shall include default values on a unit-type basis as specified in Operating Agreement, Schedule 1, section 6.6(c) and the parallel provisions of Tariff, Attachment K-Appendix, section 6.6(c). The Market Monitoring Unit shall review the Parameter Limited Schedule Matrix annually, and, in the event it determines that revision is appropriate, shall provide a revised matrix to the Office of the Interconnection by no later than December 31 prior to the annual enrollment period.

2. The Market Monitoring Unit shall notify Market Sellers of generating units and the Office of the Interconnection no later than April 1 of its determination of market power concerns raised regarding each request for a period exception or persistent exception to a value specified in the Parameter Limited Schedule Matrix or the parameters defined in Operating Agreement, Schedule 1, section 6.6 and the parallel provisions of Tariff, Attachment K-Appendix, section 6.6 and the PJM Manuals, provided that the Market Monitoring Unit receives such request by no later than February 28.

If, prior to the scheduled termination date, a Market Seller submits a request to modify a temporary exception, the Market Monitoring Unit shall review such request using the same standard utilized to evaluate period exception and persistent exception requests, and shall provide its determination of whether the request raises market power concerns, and, if so, any modifications that would alleviate those concerns, to the Market Seller, with a copy to Office of the Interconnection, by no later than 15 Business Days from the date of the modification request.

3. When a Market Seller notifies the Market Monitoring Unit of a material change to the facts relied upon by the Market Monitoring Unit and/or the Office of the Interconnection to support a parameter limited schedule period or persistent exception, the Market Monitoring Unit shall make a determination, and provide written notification to the Office of the Interconnection and the Market Seller, of any change to its determination regarding the exemption request, based on the material change in facts, by no later than 15 Business Days after receipt of such notice.

4. The Market Monitoring Unit shall notify the Office of the Interconnection of any risk premium to which it and a Market Seller owning or operating nuclear generation resource agree or its determination if agreement is not obtained. If a Market Seller submits a risk premium for its nuclear generation resource that is inconsistent with its agreement or inconsistent with the Market Monitoring Unit's determination regarding such risk premium, the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns pursuant to Tariff, Attachment M.

C. RPM Must-Offer Requirement:

1. The Market Monitoring Unit shall maintain, post on its website and provide to the Office of the Interconnection prior to each RPM Auction (updated, as necessary, on at least a quarterly basis), a list of Existing Generation Capacity Resources located in the PJM Region that are subject to the RPM must-offer requirement set forth in Tariff, Attachment DD, section 6.6.

2. The Market Monitoring Unit shall evaluate requests submitted by Capacity Market Sellers for a determination that a Generation Capacity Resource, or any portion thereof, be removed from Capacity Resource status or exempted from status as a Generation Capacity Resource subject to section II.C.1 above and inform both the Capacity Market Seller and the Office of the Interconnection of such determination in writing by no later ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction. 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 Tariff, Attachment DD.

3. The Market Monitoring Unit shall evaluate the data and documentation provided to it by a potential Capacity Market Seller to establish the EFORd to be included in a Sell Offer applicable to each resource pursuant to Tariff, Attachment DD, section 6.6(b). If a Capacity Market Seller timely submits a request for an alternative maximum level of 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 Market Monitoring Unit shall attempt to reach agreement with the Capacity Market Seller on the alternate maximum level of the 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 ninety (90) days prior to the commencement of the offer period for the Base Residual Auction for the applicable Delivery Year, the Market Monitoring Unit shall notify the Office of the Interconnection in writing, notifying the Capacity Market Seller by copy of the same, of any alternative maximum EFORd to which it and the Capacity Market Seller agree or its determination of the alternative maximum EFORd if agreement is not obtained.

4. The Market Monitoring Unit shall consider the documentation provided to it by a potential Capacity Market Seller pursuant to Tariff, Attachment DD, section 6.6 of Attachment DD, and determine whether a resource owned or controlled by such Capacity Market Seller meets the criteria to qualify for an exception to the RPM must-offer requirement because the resource (i) is reasonably expected to be physically unable to participate in the relevant auction; (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. The Market Monitoring Unit shall notify the Capacity Market Seller and the Office of the Interconnection of its determination by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction.

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.

5. If a Capacity Market Seller submits for the portion of a Generation Capacity Resource that it owns or controls, and the Office of Interconnection accepts, a Sell Offer (i) at a level of installed capacity that the Market Monitoring Unit believes is inconsistent with the level established under Tariff, Attachment DD, section 5.6.6, (ii) at a level of installed capacity inconsistent with its determination of eligibility for an exception listed in section II.C.4 above, or (iii) a maximum EFORd that the Market Monitoring Unit believes is inconsistent with the maximum level

determined under section II.C.3 of this Appendix, the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and/or request a determination from the Commission that would require the Generation Capacity Resource to submit a new or revised Sell Offer, notwithstanding any determination to the contrary made under Tariff, Attachment DD, section 6.6.

The Market Monitoring Unit shall also consider the documentation provided by the Capacity Market Seller pursuant to Tariff, Attachment DD, section 6.6, for generation resources for which the Office of the Interconnection has not approved an exception to the RPM must-offer requirement as set forth in Tariff, Attachment DD, section 6.6(g), to determine whether the Capacity Market Seller's failure to offer part or all of one or more generation resources into an RPM Auction would result in an increase of greater than five percent in any Zonal Capacity Price determined through such auction as required by Tariff, Attachment DD, section 6.6(i), and shall inform both the Capacity Market Seller and the Office of the Interconnection of its determination by no later than two (2) Business Days after the close of the offer period for the applicable RPM Auction.

D. <u>Unit Specific Minimum Sell Offers:</u>

1. If a Capacity Market Seller timely submits an exception request, with all of the required documentation as specified in Tariff, Attachment DD, section*s* 5.14(h) *and 5.14(h-1)*, the Market Monitoring Unit shall review the request and documentation and shall provide in writing to the Capacity Market Seller and the Office of the Interconnection by no later than ninety (90) days prior the commencement of the offer period for the RPM Auction in which it seeks to submit its Sell Offer (a) its determination whether the level of the proposed Sell Offer raises market power concerns, and (b) if so it shall calculate and provide to such Capacity Market Seller a minimum Sell offer Based on the data and documentation received.

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

E. <u>Market Seller Offer Caps</u>:

1. Based on the data and calculations submitted by the Capacity Market Sellers for each Existing Generation Capacity Resource and the formulas specified in Tariff, Attachment DD, section 6.7(d), the Market Monitoring Unit shall calculate the Market Seller Offer Cap for each such resource and provide it to the Capacity Market Seller and the Office of the Interconnection by no later than ninety (90) days before the commencement of the offer period for the applicable RPM Auction.

2. The Market Monitoring Unit must attempt to reach agreement with the Capacity Market Seller on the appropriate 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. If such agreement cannot be reached, then the Market Monitoring Unit shall inform the Capacity Market Seller and the Office of the Interconnection of its determination of the appropriate 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, and the Market Monitoring Unit may pursue any action available to it under Attachment M.

F. Mitigation of Offers from Planned Generation Capacity Resources:

Pursuant to Tariff, Attachment DD, section 6.5, the Market Monitoring Unit shall evaluate Sell Offers for Planned Generation Capacity Resources to determine whether market power mitigation should be applied and 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.

G. Data Submission:

Pursuant to Tariff, Attachment DD, section 6.7, the Market Monitoring Unit may request 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. All data submitted to the Office of the Interconnection or the Market Monitoring Unit by a Market Participant is subject to verification by the Market Monitoring Unit.

H. Determination of Default Avoidable Cost Rates:

1. The Market Monitoring Unit shall conduct an annual review of the table of default Avoidable Cost Rates included in Tariff, Attachment DD, section 6.7(c) and calculated on the bases set forth therein, and determine whether the values included therein need to be updated. If the Market Monitoring Unit determines that the Avoidable Cost Rates need to be updated, it shall provide to the Office of the Interconnection updated values or notice of its determination that updated values are not needed by no later than September 30th of each year.

2. The Market Monitoring Unit shall indicate in its posted reports on RPM performance the number of Generation Capacity Resources and megawatts per LDA that use the retirement default Avoidable Cost Rates.

3. If a Capacity Market Seller does not elect to use a default Avoidable Cost Rate and has timely provided to the Market Monitoring Unit its request to apply a unit-specific Avoidable Cost Rate, along with the data described in Tariff, Attachment DD, section 6.7, the Market Monitoring Unit shall calculate the Avoidable Cost Rate and provide a unit-specific value to the Capacity Market Seller for each such resource, and notify the Capacity Market Seller and the Office of the Interconnection in writing by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction whether it agrees that the unit-specific Avoidable Cost Rate is acceptable. The Capacity Market Seller and Office of the Interconnection's deadlines relating to the submittal and acceptance of a request for a unit-specific Avoidable Cost Rate are delineated in Tariff, Attachment DD, section 6.7(d).

I. Determination of PJM Market Revenues:

The Market Monitoring Unit shall calculate the Projected PJM Market Revenues for any Generation Capacity Resource to which the Avoidable Cost Rate is applied pursuant to Tariff, Attachment DD, section 6.8(d) and Tariff, Attachment DD, section 6.8(d-1), and notify the Capacity Market Seller and the Office of the Interconnection of its determination in writing by no later than one hundred fifty (150) days for the preliminary and no later than one hundred twenty-five (125) days for the final values~~ninety (90) days~~ prior to the commencement of the offer period for the applicable RPM Auction.

J. <u>Determination of Opportunity Costs</u>:

The Market Monitoring Unit shall review and verify the documentation of prices available to Existing Generation Capacity Resources in markets external to PJM and proposed for inclusion in Opportunity Costs pursuant to Tariff, Attachment DD, section 6.7(d)(ii). The Market Monitoring Unit shall notify, in writing, such Generation Capacity Resource and the Office of the Interconnection if it is dissatisfied with the documentation provided and whether it objects to the inclusion of such Opportunity Costs in a Market Seller Offer by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction. If such Generation Capacity Resource submits a Market Seller Offer that includes Opportunity Costs that have not been documented and verified to the Market Monitoring Unit's satisfaction, then the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and request a determination that would require the Generation Capacity Resource to remove them.

III. BLACKSTART SERVICE

A. Upon the submission by a Black Start Unit owner of a request for Black Start Service revenue requirements and changes to the Black Start Service revenue requirements for the Black Start Unit, the Black Start Unit owner and the Market Monitoring Unit shall attempt to agree to values on the level of each component included in the Black Start Service revenue requirements by no later than May 14 of each year. The Market Monitoring Unit shall calculate the revenue requirement for each Black Start Unit and provide its calculation to the Office of the Interconnection by no later than May 14 of each year.

B. Pursuant to the terms of Tariff, Schedule 6A and the PJM Manuals, the Market Monitoring Unit will analyze any requested generator black start cost changes on an annual basis and shall notify the Office of the Interconnection of any costs to which it and the Black Start Unit owner have agreed or the Market Monitoring Unit's determination regarding any cost components to which agreement has not been obtained. If a Black Start Unit owner includes a cost component inconsistent with its agreement or inconsistent with the Market Monitoring Unit's determination regarding such cost component, and the Office of the Interconnection accepts the Black Start Service revenue requirements submitted by the Black Start Unit owner, the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and request a determination that would require the Black Start Service generator to utilize the values determined by the Market Monitoring Unit or the Office of the Interconnection or such other values as determined by the Commission.

IV. DEACTIVATION RATES

1. Upon receipt of a notice to deactivate a generating unit under Tariff, Part V from the Office of the Interconnection forwarded pursuant to Tariff, Part V, section 113.1, the Market Monitoring Unit shall analyze the effects of the proposed deactivation with regard to potential market power issues and shall notify the Office of the Interconnection and the generator owner (or, if applicable, its designated agent) if a market power issue has been identified. The Market Monitoring Unit shall provide such notice by the following date: (a) May 31 of the current calendar year, if the Transmission Provider received the notice required pursuant to Tariff, Part V, section 113.1 between January 1 and March 31; (b) August 31 of the current calendar year, if the Transmission Provider received the notice required pursuant to Tariff, Part V, section 113.1 between April 1 and June 30; (c) November 30 of the current calendar year, if the Transmission Provider received the notice required pursuant to Tariff, Part V, section 113.1 between July 1 and September 30; or (d) February 28 of the following calendar year, if the Transmission Provider received the notice required pursuant to Tariff, Part V, section 113.1 between October 1 and December 31. Such notice shall include the specific market power impact resulting from the proposed deactivation of the generating unit, as well as an initial assessment of any steps that could be taken to mitigate the market power impact.

2. The Market Monitoring Unit and the generating unit owner shall attempt to come to agreement on the level of each component included in the Deactivation Avoidable Cost Credit. In the case of cost of service filing submitted to the Commission in alternative to the Deactivation Cost Credit, the Market Monitoring Unit shall indicate to the generating unit owner in advance of filing its views regarding the proposed method or cost components of recovery. The Market Monitoring Unit shall notify the Office of the Interconnection of any costs to which it and the generating unit owner have agreed or the Market Monitoring Unit's determination regarding any cost components to which agreement has not been obtained. If a generating unit owner includes a cost component inconsistent with its agreement or inconsistent with the Market Monitoring Unit's determination regarding such cost components, the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and seek a determination that would require the Generating unit to include an appropriate cost component. This provision is duplicated in Tariff, Part V, section 114 and Tariff, Part V, section 119.

V. OPPORTUNITY COST CALCULATION

The Market Monitoring Unit shall review requests for opportunity cost compensation under Operating Agreement, Schedule 1, section 3.2.3(f-3) and Operating Agreement, Schedule 1, section 3.2.3B(h) and the parallel provisions of Tariff, Attachment K-Appendix, section 3.2.3(f-3) and Tariff, Attachment K-Appendix, section 3.2.
3B(h), discuss with the Office of the Interconnection and individual Market Sellers the amount of compensation, and file exercise its powers to inform Commission staff of its concerns and request a determination of compensation as provided by such sections. These requirements are duplicated in Operating Agreement, Schedule 1, section 3.2.3(f-3) and Operating Agreement, Schedule 1, section 3.2.3B(h) and the paralelle provisions of Tariff, Attachment K-Appendix, section 3.2.3(f-3) and Tariff, Attachment K-Appendix, section 3.2.3B9H).

VI. FTR FORFEITURE RULE

The Market Monitoring Unit shall calculate Transmission Congestion Credits as required under Operating Agreement, Schedule 1, section 5.2.1(b) and Tariff, Attachment K-Appendix, section 5.2.1(b), including the determination of the identity of the Effective FTR Holder and an evaluation of the overall benefits accrued by an entity or affiliated entities trading in FTRs and Virtual Transactions in the Day-ahead Energy Market, and provide such calculations to the Office of the Interconnection. Nothing in this section shall preclude the Market Monitoring Unit from action to recover inappropriate benefits from the subject activity if the amount forfeited is less than the benefit derived by the Effective FTR Holder. If the Office of the Interconnection imposes a forfeiture of the Transmission Congestion Credit in an amount that the Market Monitoring Unit disagrees with, then it may exercise its powers to inform Commission staff of its concerns and request an adjustment.

VII. FORCED OUTAGE RULE

1. The Market Monitoring Unit shall observe offers submitted in the Day-ahead Energy Market to determine whether all or part of a generating unit's capacity (MW) is designated as Maximum Emergency and (i) such offer in the Real-time Energy Market designates a smaller amount of capacity from that unit as Maximum Emergency for the same time period, and (ii) there is no physical reason to designate a larger amount of capacity as Maximum Emergency in the offer in the Day-ahead Energy Market than in the Real-time Energy Market, the Market Monitoring Unit shall notify the Office of Interconnection.

2. If the Market Monitoring Unit observes that (i) an offer submitted in the Day-ahead Energy market designates all or part of capacity (MW) of a Generating unit as economic maximum that is less than the economic maximum designated in the offer in the Real-time Energy Market, and (ii) there is no physical reason to designate a lower economic maximum in the offer in the Day-ahead Energy Market than in the offer in the Real-time Energy Market, the Market Monitoring Unit shall notify the Office of Interconnection.

VIII. DATA COLLECTION AND VERIFICATION

The Market Monitoring Unit shall gather and keep confidential detailed data on the procurement and usage of fuel to produce electric power transmitted in the PJM Region in order to assist the performance of its duties under Tariff, Attachment M. To achieve this objective, the Market Monitoring Unit shall maintain on its website a mechanism that allows Members to conveniently and confidentially submit such data and develop a manual in consultation with stakeholders that describes the nature of and procedure for collecting data. Members of PJM owning a Generating unit that is located in the PJM Region (including Dynamic Transfer units), or is included in a PJM Black Start Service plan, committed as a Generation Capacity Resource for the current or future Delivery Year, or otherwise subject to a commitment to provide service to PJM, shall provide data to the Market Monitoring Unit.

4. GENERAL PROVISIONS

4.1 Capacity Market Sellers

Only Capacity Market Sellers shall be eligible to submit Sell Offers into the Base Residual Auction and Incremental Auctions. Capacity Market Sellers shall comply with the terms and conditions of all Sell Offers, as established by the Office of the Interconnection in accordance with this Attachment DD, Tariff, Attachment M, Tariff, Attachment M - Appendix and the Operating Agreement.

4.2 Capacity Market Buyers

Only Capacity Market Buyers shall be eligible to submit Buy Bids into an Incremental Auction. Capacity Market Buyers shall comply with the terms and conditions of all Buy Bids, as established by the Office of the Interconnection in accordance with this Attachment DD, Tariff, Attachment M, Tariff, Attachment M - Appendix and the Operating Agreement.

4.3 Agents

A Capacity Market Seller may participate in a Base Residual Auction or Incremental Auction through an Agent, provided that the Capacity Market Seller informs the Office of the Interconnection in advance in writing of the appointment and authority of such Agent. A Capacity Market Buyer may participate in an Incremental Auction through an Agent, provided that the Capacity Market Buyer informs the Office of the Interconnection in advance in writing of the appointment and authority of such Agent. A Capacity Market Buyer or Capacity Market Seller participating in such an auction through an Agent shall be bound by all of the acts or representations of such Agent with respect to transactions in such auction. Any written instrument establishing the authority of such Agent shall provide that any such Agent shall comply with the requirements of this Attachment DD and the Operating Agreement.

4.4 General Obligations of Capacity Market Buyers and Capacity Market Sellers

Each Capacity Market Buyer and Capacity Market Seller shall comply with all laws and regulations applicable to the operation of the Base Residual and Incremental Auctions and the use of these auctions shall comply with all applicable provisions of this Attachment DD, Tariff, Attachment M, Tariff, Attachment M - Appendix, Tariff, Attachment Q, the Operating Agreement, and the Reliability Assurance Agreement, Tariff, Attachment K-Appendix, section 1.4 and the parallel provisions of Operating Agreement, Schedule 1, section 1.4, and all procedures and requirements for the conduct of the Base Residual and Incremental Auctions and the PJM Region established by the Office of the Interconnection in accordance with the foregoing.

4.5 Confidentiality

The following information submitted to the Office of the Interconnection in connection with any Base Residual Auction, Incremental Auction, or Reliability Backstop Auction. ~~, or Capacity~~

~~Performance Transition Incremental Auction~~ shall be deemed confidential information for purposes of Operating Agreement, section 18.17, Tariff, Attachment M and Tariff, Attachment M - Appendix: (i) the terms and conditions of the Sell Offers and Buy Bids; and (ii) the terms and conditions of any bilateral transactions for Capacity Resources.

4.6 Bilateral Capacity Transactions

(a) Unit-Specific Internal Capacity Bilateral Transaction Transferring All Rights and Obligations ("Section 4.6(a) Bilateral").

(i) Market Participants may enter into unit-specific internal bilateral capacity contracts for the purchase and sale of title and rights to a specified amount of installed capacity from a specific generating unit or units. Such bilateral capacity contracts shall be for the transfer of rights to capacity to and from a Market Participant and shall be reported to the Office of the Interconnection in accordance with this Attachment DD and the Office of the Interconnection's rules related to its "capacity exchange" tool.

(ii) For purposes of clarity, with respect to all Section 4.6(a) Bilateral transactions, the rights to, and obligations regarding, the capacity that is the subject of the transaction shall pass to the buyer under the contract at the location of the unit and further transactions and rights and obligations associated with such capacity shall be the responsibility of the buyer under the contract. Such obligations include any charges, including penalty charges, relating to the capacity under this Attachment DD. In no event shall the purchase and sale of the rights to capacity pursuant to a Section 4.6(a) Bilateral constitute a transaction with the Office of the Interconnection or PJMSettlement or a transaction in any auction under this Attachment DD.

(iii) All payments and related charges associated with a Section 4.6(a) Bilateral shall be arranged between the parties to the transaction and shall not be billed or settled by the Office of the Interconnection or PJMSettlement. The Office of the Interconnection, PJMSettlement, and the Members will not assume financial responsibility for the failure of a party to perform obligations owed to the other party under a Section 4.6(a) Bilateral reported to the Office of the Interconnection under this Attachment DD.

(iv) With respect to capacity that is the subject of a Section 4.6(a) Bilateral that has cleared an auction under this Attachment DD prior to a transfer, the buyer of the cleared capacity shall be considered in the Delivery Year the party to a transaction with PJMSettlement as Counterparty for the cleared capacity at the Capacity Resource Clearing Price published for the applicable auction.

(v) A buyer under a Section 4.6(a) Bilateral contract shall pay any penalties or charges associated with the capacity transferred under the contract. To the extent the capacity that is the subject of a Section 4.6(a) Bilateral contract has cleared an auction under this Attachment DD prior to a transfer, then the seller under the contract also shall guarantee and indemnify the Office of the Interconnection, PJMSettlement, and the Members for the buyer's obligation to pay any penalties or charges associated with the capacity and for which payment is not made to PJMSettlement by the buyer as determined by the Office of the Interconnection. All claims regarding a default of a buyer to a seller under a Section 4.6(a) Bilateral contract shall be resolved solely between the buyer and the seller.

(vi) To the extent the capacity that is the subject of the Section 4.6(a) Bilateral transaction already has cleared an auction under this Attachment DD, such bilateral capacity transactions shall be subject to the prior consent of the Office of the Interconnection and its determination that sufficient credit is in place for the buyer with respect to the credit exposure associated with such obligations.

(b) Bilateral Capacity Transaction Transferring Title to Capacity But Not Transferring Performance Obligations ("Section 4.6(b) Bilateral").

(i) Market Participants may enter into bilateral capacity transactions for the purchase and sale of a specified megawatt quantity of capacity that has cleared an auction pursuant to this Attachment DD. The parties to a Section 4.6(b) Bilateral transaction shall identify (1) each unit from which the transferred megawatts are being sold, and (2) the auction in which the transferred megawatts cleared. Such bilateral capacity transactions shall transfer title and all rights with respect to capacity and shall be reported to the Office of the Interconnection on an annual basis prior to each Delivery Year in accordance with this Attachment DD and pursuant to the Office of the Interconnection's rules related to its "capacity exchange" tool. Reported transactions with respect to a unit will be accepted by the Office of the Interconnection only to the extent that the total of all bilateral sales from the reported unit (including Section 4.6(a) Bilaterals, Section 4.6(b) Bilaterals, and Locational UCAP bilaterals) do not exceed the unit's cleared unforced capacity.

(ii) For purposes of clarity, with respect to all Section 4.6(b) Bilateral transactions, the rights to the capacity shall pass to the buyer at the location of the unit(s) specified in the reported transaction. In no event shall the purchase and sale of the rights to capacity pursuant to a Section 4.6(b) Bilateral constitute a transaction with PJMSettlement or the Office of the Interconnection or a transaction in any auction under this Attachment DD.

(iii) With respect to a Section 4.6(b) Bilateral, the buyer of the cleared capacity shall be considered in the Delivery Year the party to a transaction with PJMSettlement as Coutnerparty for the cleared capacity at the Capacity Resource Clearing Price published for the applicable auction; provided, however, with respect to all Section 4.6(b) Bilateral transactions, such transactions do not effect a novation of the seller's obligations to make RPM capacity available to PJM pursuant to the terms and conditions originally agreed to by the seller; provided further, however, the buyer shall indemnify PJMSettlement, the LLC, and the Members for any failure by a seller under a Section 4.6(b) Bilateral to meet any resulting obligations, including the obligation to pay deficiency penalties and charges owed to PJMSettlement, associated with the capacity.

(iv) All payments and related charges associated with a Section 4.6(b) Bilateral shall be arranged between the parties to the contract and shall not be billed or settled by the Office of the Interconnection or PJMSettlement. The Office of the Interconnection, PJMSettlement, and the Members will not assume financial responsibility for the failure of a party to perform obligations owed to the other party under a Section 4.6(b) Bilateral capacity contract reported to the Office of the Interconnection under this Attachment DD.

(v) All claims regarding a default of a buyer to a seller under a Section 4.6(b) Bilateral shall be resolved solely between the buyer and the seller.

(c) Locational UCAP Bilateral Transactions Between Capacity Sellers.

(i) Market Participants may enter into Locational UCAP bilateral transactions which shall be reported to the Office of the Interconnection in accordance with this Attachment DD and the LLC's rules related to its "capacity exchange" tool.

(ii) For purposes of clarity, with respect to all Locational UCAP bilateral transactions, the rights to the Locational UCAP that are the subject of the Locational UCAP bilateral transaction shall pass to the buyer under the Locational UCAP bilateral contract subject to the provisions of Tariff, Attachment DD, section 5.3A. In no event, shall the purchase and sale of Locational UCAP pursuant to a Locational UCAP bilateral transaction constitute a transaction with the Office of the Interconnection or PJMSettlement, or a transaction in any auction under this Attachment DD.

(iii) A Locational UCAP Seller shall have the obligation to make the capacity available to PJM in the same manner as capacity that has cleared an auction under this Attachment DD and the Locational UCAP Seller shall have all obligations for charges and penalties associated with the capacity that is the subject of the Locational UCAP bilateral contract; provided, however, the buyer shall indemnify PJMSettlement, the LLC, and the Members for any failure by a seller to meet any resulting obligations, including the obligation to pay deficiency penalties and charges owed to PJMSettlement, associated with the capacity. All claims regarding a default of a buyer to a seller under a Locational UCAP bilateral contract shall be resolved solely between the buyer and the seller.

(iv) All payments and related charges for the Locational UCAP associated with a Locational UCAP bilateral contract shall be arranged between the parties to such bilateral contract and shall not be billed or settled by the Office of the Interconnection or PJMSettlement. The LLC, PJMSettlement, and the Members will not assume financial responsibility for the failure of a party to perform obligations owed to the other party under a Locational UCAP bilateral contract reported to the Office of the Interconnection under this Attachment DD.

(d) The bilateral transactions provided for in this section 4.6 shall be for the physical transfer of capacity to or from a Market Participant and shall be reported to and coordinated with the Office of the Interconnection in accordance with this Attachment DD and pursuant to the Office of the Interconnection's rules relating to its "capacity exchange" tool. Bilateral transactions that do not contemplate the physical transfer of capacity to and from a Market Participant are not subject to this Attachment DD and shall not be reported to and coordinated with the Office of the Interconnection.

(e) Effective with the 2022/2023 Delivery Year, any bilateral transaction provided for in this section 4.6 for replacement capacity shall be given no effect in satisfying the buyer's obligations under this Attachment DD to the extent that the resource that is the subject of the transaction is a Capacity Resource with State Subsidy for which the Capacity Market Seller has not elected to forego receipt of any State Subsidy for the relevant Delivery Year and does not qualify for one of the categorical exemptions described in Tariff, Attachment DD, sections 5.14(h-1)(5) through 5.14(h-1)(8) and the purchased capacity is then used to replace capacity from a Capacity Resource that (1) is not a Capacity Resource with State Subsidy or (2) is a Capacity Resource with State Subsidy for which the Capacity Market Seller elected the competitive exemption pursuant Tariff, Attachment DD, section 5.14(h-1)(4) or reported that it will forego receipt of any State Subsidy for the relevant Delivery Year, all as in accordance with the PJM Manuals.

(f) For the 2025/2026 Delivery Year and all subsequent Delivery Years, Market Participants may adjust the expected performance of a Capacity Resource by entering into a bilateral capacity obligation transaction for the purchase and sale of a specified megawatt quantity of committed capacity that is subject to the performance obligations and provisions of Tariff, Attachment DD, section 10A ("PAI Obligation Transfer"). The seller of the PAI Obligation Transfer transaction has a Performance Assessment Interval obligation on a resource that will be transferred to and received by the buyer's resource as a result of the transaction.

(i) PAI Obligation Transfers shall be reported to the Office of the Interconnection in accordance with this Attachment DD and the Office of the Interconnection's rules related to its "capacity exchange" tool, where the parties in such transaction shall identify (1) the transferring resource of the seller from which the megawatts are being sold, (2) the megawatt quantity of committed capacity to be transferred, (3) the effective time period for which the PAI Obligation Transfer applies, which may be set on an interval basis, and (4) the receiving Capacity Resource of the buyer that will assume the performance obligation of the transferred capacity. Such transactions must be reported and approved by both parties prior to the start of the effective time period of the transfer.

(ii) The effect of a PAI Obligation Transfer is to modify the committed capacity and resulting expected performance of the transferring and receiving resources when assessing the performance shortfall or bonus during a Performance Assessment Interval within Tariff, Attachment DD, section 10A, where the transferring resource will have a reduction in expected performance and the receiving resource will have an increase in expected performance during Performance Assessment Intervals that occur within the effective time period of the transfer. PAI Obligation Transfers do not affect in any way the capacity rights and obligations of the parties and reported resources beyond Tariff, Attachment DD, section 10A.

(iii) The performance obligations of the transferred capacity and any associated Non-Performance Charges under Tariff, Attachment DD, section 10A shall pass to the buyer; provided, however, the seller shall guarantee and indemnify the Office of the Interconnection, PJMSettlement, and the Members for any failure by the buyer to pay any non-performance charges owed to PJMSettlement associated with the transferred capacity.

(iv) For a PAI Obligation Transfer to be accepted by the Office of the Interconnection and take effect for a Performance Assessment Interval, the following criteria must be satisfied, as further described in the PJM Manuals:

(A) The receiving resource reported in the PAI Obligation Transfer must provide the same locational value of capacity (with consideration of remaining import capability into LDAs) as the transferring resource, and both resources must be included in the area of the Performance Assessment Interval; and

(B) The resulting quantity of capacity that is subject to performance obligations under this Tariff, Attachment DD, section 10A on the receiving Capacity Resource reported in the PAI Obligation Transfer shall not exceed the installed capacity or Capacity Interconnection Rights of the receiving resource.

(v) All payments and related charges associated with a PAI Obligation Transfer shall be arranged between the parties to the transaction and shall not be billed or settled by the Office of the Interconnection or PJMSettlement. The Office of the Interconnection, PJMSettlement, and the Members will not assume financial responsibility for the failure of a party to perform obligations owed to the other party under a PAI Obligation Transfer reported to 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 Tariff, Attachment DD, section 5.12(a) and section 5.14(a) above.

(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) above; 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 Tariff, Attachment DD, section 5.12(a), 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) above that is entitled to compensation pursuant to section 5.14(b) above; 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) above 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) above. Other capacity resources that clear the BRA in such LDA receive the Capacity Resource Clearing Price as determined in section 5.14(a) above.

6. The failure to submit a Sell Offer consistent with section 5.14(c)(i)-(iii) above 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) above 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 Tariff, Attachment DD, section 5.10(a)(ii).

~~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 Tariff, Attachment DD, 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 Tariff, Attachment DD, section 5.14B, Tariff, Attachment DD, section 5.14C, Tariff, Attachment DD, section 5.14D, Tariff, Attachment DD, section 5.14E and Tariff, Attachment DD, section 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~~3) an adjustment, if required, to account for Resource Make-Whole Payments; and ~~(5~~4) 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~~3) 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~~4) 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 New Generation Capacity Resources that are not Capacity Resources with State Subsidy for up to the 2022/2023 Delivery Year.

(1) The provisions of this section 5.14(h) shall not be effective after the 2022/2023 Delivery Year. 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 Tariff, Attachment DD, section 5.10(a)(iv)(A) of this Attachment. This section only applies to new Generation Capacity Resources that do not receive or are not entitled to receive a State Subsidy, meaning that such resources are not Capacity Resources with State Subsidy. To the extent a new Generation Capacity Resource is a Capacity Resource with State Subsidy, then the provisions in Tariff, Attachment DD, section 5.14(h-1) apply.

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	128,990	130,300
CC $/MW-yr	185,700	176,000	172,600	179,400

(2) 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 Tariff, Attachment DD, 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 the 2022/2023 Delivery Year, for purposes of this provision, the net energy and ancillary services revenue estimate for a combustion turbine generator shall be that determined by Tariff, Attachment DD, section 5.10(a)(v-1)(A), provided that the energy and ancillary services 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 6.501 MMbtu/MWh, the variable operations and maintenance expenses for such resource shall be $2.11 per MWh, a 10% adder will not be included in the energy offer, and the reactive service revenues shall be $3,350 per MW-year.

(4) Any Sell Offer that is based on either (i) or (ii), and (iii):

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;

iii) in any LDA for which a separate VRR Curve is established for use in the Base Residual Auction for the Delivery Year relevant to the RPM Auction in which such offer is submitted, and that is less than 90 percent of the applicable Net Asset Class Cost of New Entry or, if there is no applicable Net Asset Class Cost of New Entry, less than 70 percent of the Net Asset Class Cost of New Entry for a combustion turbine generator as provided in subsection (h)(1) above shall be set to equal 90 percent of the applicable Net Asset Class Cost of New Entry (or set equal to 70 percent of such cost for a combustion turbine, where there is no otherwise applicable net asset class figure), unless the Capacity Market Seller obtains the prior determination from the Office of the Interconnection described in subsection (5) hereof. This provision applies to Sell Offers submitted in Incremental Auctions conducted after December 19, 2011, provided that the Net Asset Class Cost of New Entry values for any such Incremental Auctions for the 2012-13 or 2013-14 Delivery Years shall be the Net Asset Class Cost of New Entry values posted by the Office of the Interconnection for the Base Residual Auction for the 2014-15 Delivery Year.

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

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

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

The request also shall identify all revenue sources relied upon in the Sell Offer to offset the claimed fixed costs, including, without limitation, long-term power supply contracts, tolling agreements, or tariffs on file with state regulatory agencies, and shall demonstrate that such offsetting revenues are consistent, over a reasonable time period identified by the Capacity Market Seller, with the standard prescribed above.

For the 2022/2023 Delivery Year, in making such demonstration, the Capacity Market Seller may rely upon revenues projected by well defined, forward-looking dispatch models, designed to generally follow the rules and processes of PJM's energy and ancillary services markets. Such models must utilize publicly available forward prices for electricity and fuel in the PJM Region. Any modifications made to the forward electricity and fuel prices must similarly use publicly available data. Alternative forward prices for fuel may be used if accompanied by contractual evidence showing the applicability of the alternative fuel price. Where forward fuel markets are not available, publicly available estimates of future fuel prices may be used. The model shall also contain estimates of variable operation and maintenance costs, which may include Maintenance Adders, and emissions allowance prices. Documentation for net revenues also must 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, capacity factors and ancillary service capabilities.

In the alternative, the Capacity Market Seller may request that the Market Monitoring Unit, subject to acceptance by the Office of Interconnection, produce a resource-specific Energy & Ancillary Services Offset value for such resource using the Forward Hourly LMPs, Forward Hourly Ancillary Service Prices, and either Forward Daily Natural Gas Prices for combustion turbines and combined cycle resources, or forecasted fuel prices for other resource types, and plant parameters and capability information specific to the dispatch of the resource, as outlined above. In addition to the documentation identified herein and in the PJM Manuals, the Capacity Market Seller shall provide any additional supporting information reasonably requested by the Office of the Interconnection or the Market Monitoring Unit to evaluate the Sell Offer. Requests for additional documentation will not extend the deadline by which the Office of the Interconnection or the Market Monitoring Unit must provide their determinations of the Minimum Offer Price Rule exception request.

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

iv) The Market Monitoring Unit shall review the information and documentation in support of the request and shall provide its findings whether the proposed Sell Offer is acceptable, in accordance with the standards and criteria hereunder, in writing, to the Capacity Market Seller and the Office of the Interconnection by no later than ninety (90) days prior to the commencement of the offer period for such auction. The Office of the Interconnection shall also review all exception requests and documentation and shall provide in writing to the Capacity Market Seller, and the Market Monitoring Unit, its determination whether the requested Sell Offer is acceptable and if not it shall calculate and provide to such Capacity Market Seller, a minimum Sell Offer based on the data and documentation received, by no later than sixty-five (65) days prior to the commencement of the offer period for the relevant RPM Auction. If the Office of the Interconnection determines that the requested Sell Offer is acceptable, the Capacity Market Seller Shall notify the Market Monitoring Unit and the Office of the Interconnection, in writing, of the minimum level of Sell Offer to which it agrees to commit by no later than sixty (60) days prior to the commencement of the offer period for the relevant RPM Auction.

h-1) Minimum Offer Price Rule for Capacity Resources with State Subsidy for the 2022/2023 Delivery Year.

(1) **General Rule.** The provisions of this section 5.14(h-1) shall not be effective after the 2022/2023 Delivery Year. For the 2022/2023 Delivery Year, any Sell Offer based on either a New Entry Capacity Resource with State Subsidy 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 that qualifies for any of the exemptions defined in Tariff, Attachment DD, sections 5.14(h-1)(4)-(8), the Sell Offer for such resource shall not be limited by the MOPR Floor Offer Price, unless otherwise specified.

(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 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, 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. 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. Notwithstanding, if a Capacity Market Seller submits a timely resource-specific exception pursuant to Tariff, Attachment DD, section 5.14(h-1)(3) for the relevant Delivery Year, and PJM approves the resource-specific MOPR Floor Offer Price, then the Capacity Market Seller may use such floor price regardless of whether it timely certified whether or not the resource is a Capacity Resource with State Subsidy.

(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 Renewable Portfolio Standard 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 material change in status as a Capacity Resource with State Subsidy within 30 days of such material change, unless such material change occurs within 30 days of the commencement of the offer period of any RPM Auction for the 2022/2023 Delivery Year, in which case the Market Seller must notify PJM no later than 5 days prior to the commencement of the offer period of any RPM Auction for the 2022/2023 Delivery Year. Nothing in this provision shall supersede the requirement for all Capacity Market Sellers to certify to the Office of Interconnection whether its resource meets the criteria of a Capacity Resource with State Subsidy pursuant to Tariff, Attachment DD, section 5.14(h-1)(1)(C)(i).

(2) **Minimum Offer Price Rule.** Any Sell Offer for a New Entry Capacity Resource with State Subsidy 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-1)(4)-(8), shall have an offer price no lower than the applicable MOPR Floor Offer Price, unless the applicable MOPR Floor Offer Price is higher than the applicable Market Seller Offer Cap, in which circumstance the Capacity Resource with State Subsidy must seek a resource-specific value determined in accordance with the resource-specific MOPR Floor Offer Price process to participate in an RPM Auction.

(A) New Entry MOPR Floor Offer Price. For a New Entry Capacity Resource with State Subsidy 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-1)(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, 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	$271
Tracking Solar PV	$290
Onshore Wind	$420
Offshore Wind	$1,155
Battery Energy Storage	$532
Diesel Backed Demand Resource	$254

The gross cost of new entry values in the table above are expressed in dollars per MW-day in terms of nameplate megawatts. For purposes of submitting a Sell Offer, the gross cost of new entry values must be converted to a net cost of new entry by subtracting the estimated net energy and ancillary service revenues, as determined below, from the gross cost of new entry. However, the resultant net cost of new entry of the battery energy storage resource type in the table above must be multiplied by 2.5. The net cost of new entry based on nameplate capacity is then converted to Unforced Capacity ("UCAP") MW-day. For Delivery Years through the 2022/2023 Delivery Year, to determine the applicable UCAP MW-day value, the net cost of new entry is adjusted as follows: for thermal generation resource types and battery energy storage resource types, the applicable class average EFORd; for wind and solar generation resource types, the applicable class average capacity value factor; or for Demand Resources and Energy Efficiency Resources, the Forecast Pool Requirement, as applicable to the relevant RPM Auction. For the 2023/2024 Delivery Year and subsequent Delivery Years, to determine the applicable UCAP MW-day value, the net cost of new entry is adjusted as follows: for thermal generation resource types, the applicable class average EFORd; for battery storage, wind, and solar resource types, the applicable ELCC Class Rating; or for Demand Resources and Energy Efficiency Resources, the Forecast Pool Requirement, as applicable to the relevant RPM Auction. The resulting default New Entry MOPR Floor Offer price in UCAP/MW-day terms shall be applied to each MW offered for the Capacity Resource regardless of the actual Sell Offer quantity and regardless of whether the Sell Offer is for a Seasonal Capacity Performance Resource.

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.

For generation-backed Demand Resources that are not powered by diesel generators, the default New Entry MOPR Floor Offer Price shall be the default New Entry MOPR Floor Offer Price applicable to their technology type. Generation-backed Demand Resources using a technology type 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 in Tariff, Attachment DD, section 5.14(h-1)(3) below to participate in an RPM Auction.

The default gross cost of new entry for Energy Efficiency Resources shall be $644/ICAP MW-Day, which shall be offset by projected wholesale energy savings, as well as transmission and distribution savings of $95/ICAP MW-Day, to determine the default New Entry MOPR Floor Offer Price (Net Cost of New Entry), where the projected wholesale energy savings are determined utilizing the cost and performance data of relevant programs offered by representative energy efficiency programs with sufficiently detailed publicly available data. The wholesale energy savings, in $/ICAP MW-day, shall be calculated prior to each RPM Auction and be equal to the average annual energy savings of 6,221 MWh/ICAP MW times the weighted average of the annual real-time Forward Hourly LMPs of the Zones of the representative energy efficiency programs, where the weighting is developed from the annual energy savings in the relevant Zones, divided by 365.

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, combine cycle, and generation-backed Demand 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 shall be the average of the net energy and ancillary services revenues that the resource is projected to receive from the PJM energy and ancillary service markets for the applicable Delivery Year from three separate simulations, with each such simulation using forward prices shaped using historical data from one of each of the three consecutive calendar years preceding the time of the determination for the RPM Auction to take account of year-to-year variability in such hourly shapes. Each net energy and ancillary services revenue simulation shall be conducted in accordance with the following and the PJM Manuals:

(i) for nuclear resource type, the net energy and ancillary services revenue estimate for each Zone shall be determined by the gross energy market revenue determined by the product of [average annual day-ahead Forward Hourly LMPs for such Zone, 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 reactive services revenue of $3,350/MW-year;

(ii) for coal resource type, the net energy and ancillary services revenue estimate for each Zone shall be determined by the Projected EAS 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 day-ahead and real-time Forward Hourly LMPs for such Zone and Forward Hourly Ancillary Service Prices, and daily forecasted coal prices, as set forth in the PJM Manuals, plus reactive services revenue of $3,350/MW-year;

(iii) for combustion turbine resource type, the net energy and ancillary services revenue estimate for each Zone shall be determined in a manner consistent with the methodology described in Tariff, Attachment DD, section 5.10(a)(v-1)(B) for the Reference Resource combustion turbine.

(iv) for combined cycle resource type, the net energy and ancillary services revenue estimate for each Zone 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 6,501 BTU/kwh, the variable operations and maintenance expenses for such resource, inclusive of Maintenance Adder costs, shall be $2.11/MWh, plus reactive services revenue of $3,350/MW-year.

(v) for solar PV resource type, the net energy and ancillary services revenue estimate for each Zone 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 Forward Hourly LMP for such Zone and applicable to such hour with this product summed across all of the hours of an annual period, plus reactive 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 for each Zone 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 Forward Hourly LMP for such Zone applicable to such hour with this product summed across all of the hours of an annual period, plus reactive services revenue of $3,350/MW-year;

(vii) for offshore wind resource type, the net energy and ancillary services revenue estimate for each Zone shall be determined by the gross energy market revenue equal to the product of [the average annual real-time Forward Hourly LMP for such Zone times 8,760 hours times an assumed annual capacity factor of 45%], plus reactive services revenue of $3,350/MW-year;

(viii) for Capacity Storage Resource, the net energy and ancillary services revenue estimate shall be estimated by the Projected EAS Dispatch of a 1 MW, 4MWh resource, with an 85% roundtrip efficiency, and assumed to be dispatched between 95% and 5% state of charge against day-ahead and real-time Forward Hourly LMPs for such Zone and Forward Hourly Ancillary Service Prices, plus reactive services revenue of $3,350/MW-year; and

(ix) for generation-backed Demand Resource, the net energy and ancillary services revenue estimate shall be zero dollars.

New Entry Capacity Resource with State Subsidy for which there is no default MOPR Floor Offer Price provided in accordance with this section, including hybrid resources, 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.

(i) 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, (a) based on the resource-specific MOPR Floor Offer Price , as determined in accordance with Tariff, Attachment DD, section 5.14(h-1)(3) below, or (b) if available, the default Avoidable Cost Rate for the applicable resource type shown in the table below, net of projected PJM market revenues equal to the resource's net energy and ancillary service revenues for the resource type, as determined in accordance with subsection (ii) below.

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
Diesel-backed Demand Response	$3
Load-backed Demand Response	$0
Energy Efficiency	$0

The default gross Avoidable Cost Rate values in the table above are expressed in dollars per MW-day in terms of nameplate megawatts. For purposes of submitting a Sell Offer, the default Avoidable Cost Rate values must be net of estimated net energy and ancillary service revenues, and then the difference is ultimately converted to Unforced Capacity ("UCAP") MW-day, where the UCAP MW-day value will be determined based on: for Delivery Years through the 2022/2023 Delivery Year, the resource-specific EFORd for thermal generation resource types, resource-specific capacity value factor for solar and wind generation resource types (based on the ratio of Capacity Interconnection Rights to nameplate capacity, appropriately time-weighted for any winter Capacity Interconnection Rights), or the Forecast Pool Requirement for Demand Resources and Energy Efficiency Resources, as applicable to the relevant RPM Auction, and for the 2023/2024 Delivery Year and subsequent Delivery Years, the resource-specific EFORd for thermal generation resource types and on the resource-specific Accredited UCAP value for solar and wind resource types (with appropriate time-weighting for any winter Capacity Interconnection Rights), or the Forecast Pool Requirement for Demand Resources and Energy Efficiency Resources, as applicable to the relevant RPM Auction. The resulting default Cleared MOPR Floor Offer price in UCAP/MW-day terms shall be applied to each MW offered for the Capacity Resource regardless of actual Sell Offer quantity and regardless of whether the Sell Offer is for a Seasonal Capacity Performance Resource.

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.

For generation-backed Demand Resources that are not powered by diesel generators, the default Cleared MOPR Floor Offer Price shall be the default Cleared MOPR Floor Offer Price applicable to their technology type. Generation-backed Demand Resources using a technology type 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 in Tariff, Attachment DD, section 5.14(h-1)(3) below to participate in an RPM Auction.

Cleared Capacity Resources with State Subsidy for which there is no default MOPR Floor Offer Price provided in accordance with this section, including hybrid resources, 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.

(ii) The net energy and ancillary services revenue is equal to forecasted net revenues which shall be determined in accordance with the applicable resource type net energy and ancillary services revenue determination methodology set forth in Tariff, Attachment DD, section 5.14(h-1)(2)(A)(i) through (ix) and using the subject resource's operating parameters as determined in accordance with the PJM Manuals based on (a) offers submitted in the Day-ahead Energy Market and Real-time Energy Market over the calendar year preceding the time of the determination for the RPM Auction; (b) the resource-specific operating parameters approved, as applicable, in accordance with Operating Agreement, Schedule 1, section 6.6(b) and Operating Agreement, Schedule 2 (including any Fuel Costs, emissions costs, Maintenance Adders, and Operating Costs); (c) the resource's EFORd; (d) Forward Hourly LMPs at the generation bus as determined in accordance with Tariff, Attachment DD, section 5.10(a)(v-1)(C)(6); and (e) the resource's stated annual revenue requirement for reactive services; plus any unit-specific bilateral contract. In addition, the following resource type-specific parameters shall be considered; (f) for combustion turbine, combined cycle, and coal resource types: the installed capacity rating, ramp rate (which shall be equal to the maximum ramp rate included in the resource's energy offers over the most recent previous calendar year preceding the determination for the RPM Auction), and the heat rate as determined as the resource's average heat rate at full load as submitted to the Market Monitoring Unit and the Office of the Interconnection, where for combined cycle resources heat rates will be determined at base load and at peak load (e.g., without duct burners and with duct burners), as applicable; (g) for nuclear resource type: an average equivalent availability factor of all PJM nuclear resources to account for refueling outages; (h) for solar and wind resource types: the resource's output profiles for the most recent three calendar years, as available; and (i) for battery storage resource type: the nameplate capacity rating (on a MW / MWh basis).

To the extent the resource has not achieved commercial operation, the operating parameters used in the simulation of the net energy and ancillary service revenues will be based on the manufacturer's specifications and/or from parameters used for other existing, comparable resources, as developed by the Market Monitoring Unit and the Capacity Market Seller, and accepted by the Office of the Interconnection.

A Capacity Market Seller intending to submit a Sell Offer in any RPM Auction for a Cleared Capacity Resource with State Subsidy based on a net energy and ancillary services revenue determination that does not use the foregoing methodology or parameter inputs stated for that resource type shall, at its election, submit a request for a resource-specific MOPR Floor Offer Price for such Capacity Resource pursuant to Tariff, Attachment DD, section 5.14(h-1)(3) below.

(3) Resource-Specific Exception. A Capacity Market Seller intending to submit a Sell Offer in any RPM Auction for a New Entry Capacity Resource with State Subsidy 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. The resource-specific MOPR Floor Offer Price determined under this provision shall be based on the resource-specific EFORd for thermal generation resource types, on the resource-specific Accredited UCAP value for ELCC Resources (where for solar and wind generation resource types the Accredited UCAP shall be appropriately time-weighted for any winter Capacity Interconnection Rights), or the Forecast Pool Requirement for Demand Resources and Energy Efficiency Resources, as applicable to the relevant RPM Auction and shall be applied to each MW offered by the resource regardless of actual Sell Offer quantity and regardless of whether the Sell Offer is for a Seasonal Capacity Performance Resource. 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-1)(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 with State Subsidy, 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 revenues projected by well-defined, forward-looking dispatch models designed to generally follow the rules and processes of PJM's energy and ancillary services market. Such models must utilize publicly available forward prices for electricity and fuel in the PJM Region. Any modifications made to the forward electricity and fuel prices must similarly use publicly available data. Alternative forward prices for fuel may be used if accompanied by contractual evidence showing the applicability of the alternative fuel price. Where forward fuel markets are not available, publicly available estimates of future fuel prices may be used. The model shall also contain estimates of variable operation and maintenance expenses, which may include Maintenance Adders, and emissions allowance prices. Documentation for net revenues also must 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, capacity factors, 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 the alternative, the Capacity Market Seller may request that the Market Monitoring Unit, subject to acceptance by the Office of Interconnection, produce a resource-specific Energy & Ancillary Services Offset value for such resource using the Forward Hourly LMPs, Forward Hourly Ancillary Service Prices and either Forward Daily Natural Gas Prices for combustion turbines and combined cycle resources, or forecasted fuel prices for other resource types, plus plant parameters and capability information specific to the dispatch of the resource, as outlined above. 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 consider all costs associated with the generation unit supporting the Demand Resource, and 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.

(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 shall, 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 revenues projected by well-defined, forward-looking dispatch models designed to generally follow the rules and processes of PJM's energy and ancillary services market. Such models must utilize publicly available forward prices for electricity and fuel in the PJM Region. Any modifications made to the forward electricity and fuel prices must similarly use publicly available data. Alternative forward prices for fuel may be used if accompanied by contractual evidence showing the applicability of the alternative fuel price. Where forward fuel markets are not avaliable, publicly avaliable estimates of future fuel sources may be used. The model shall also contain estimates of variable operation and maintenance expenses, which may include Maintenance Adders, and emissions allowance prices. Documentation for net revenues also must 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, capacity factors, 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.

In the alternative, the Capacity Market Seller may request that the Market Monitoring Unit, subject to acceptance by the Office of Interconnection, produce a resource-specific Energy & Ancillary Services Offset value for such resource using the Forward Hourly LMPs, Forward Hourly Ancillary Service Prices and either Forward Daily Natural Gas Prices for combustion turbines and combined cycle resources, or forecasted fuel prices for other resource types, plus plant parameters and capability information specific to the dispatch of the resource, as outlined above. 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 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 all costs associated with the generation unit supporting the Demand Resource, and 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.

(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 under this subsection 5.14(h-1) 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 unless the Self-Supply Entity certifies, subject to PJM and Market Monitor review, that the Capacity Resource will not accept a State Subsidy, including any financial benefit that is the result of being owned by a regulated utility, such that retail ratepayers are held harmless, (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, or (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 (unless the underlying Capacity Resource that is the subject of a bilateral transaction has not received, is not receiving, and is not entitled to receive any State Subsidy except those that are assigned (i.e., renewable energy credits) to the off-takers of a bilateral transaction and the Capacity Market Seller of such Capacity Resource can demonstrate and certify that the Capacity Market Seller's rights and obligations of its share of the capacity, energy, and assignable State Subsidy associated with the underlying Capacity Resource are in pro rata shares). A new Generation Capacity Resource that is a Capacity Resource with State Subsidy may elect the competitive exemption; however, in such instance, the applicable MOPR Floor Offer Price will be determined in accordance with the minimum offer price rules for certain new Generation Capacity Resources as provided in Tariff, Attachment DD, section 5.14(h), which apply the minimum offer price rule to the new Generation Capacity Resources located in an LDA where a separate VRR Curve is established as provided in Tariff, Attachment DD, section 5.14(h)(4).

(B) 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.

(5) Self-Supply Entity exemption. A Capacity Resource that was owned, or bilaterally contracted, by a Self-Supply Entity on December 19, 2019, shall be exempt from the Minimum Offer Price Rule if such Capacity Resource remains owned or bilaterally contracted by such Self-Supply Entity and 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 wholesale market participation agreement executed by the interconnection customer 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 wholesale market participation agreement filed by PJM with the Commission on or before December 19, 2019.

(6) Renewable Portfolio Standard Exemption. A Capacity Resource with State Subsidy 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 as of December 19, 2019 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 wholesale market participation agreement executed by the interconnection customer 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 wholesale market participation agreement filed by PJM with the Commission on or before December 19, 2019.

(7) Demand Resource and Energy Efficiency Resource Exemption.

(A) 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:

(i) has successfully cleared an RPM Auction prior to December 19, 2019. For purposes of this subsection (A), individual customer location registrations 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

(ii) has completed registration on or before December 19, 2019; or

(iii) 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).

(B) All registered locations that qualify for the Demand Resource and Energy Efficiency Resource exemption shall continue to remain exempt even if the MW of nominated capacity increases between RPM Auctions unless any MW increase in the nominated capacity is due to an investment made for the sole purpose of increasing the curtailment capability of the location in the capacity market. In such case, the MW of increased capability will not be qualified for the Demand Resource and Energy Efficiency Resource exemption.

(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 wholesale market participation agreement executed by the interconnection customer 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 wholesale market participation agreement 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.

h-2) Minimum Offer Price Rule Effective with the 2023/2024 Delivery Year

(1) **Certification Requirement.**

(A) By no later than one hundred and fifty (150) days prior to the commencement of the offer period of any RPM Auction conducted for the 2024/2025 Delivery Year and all subsequent Delivery Years, and by the date posted on the PJM website for the 2023/2024 Delivery Year, each Capacity Market Seller must certify to the Office of Interconnection for each Generation Capacity Resource the Capacity Market Seller intends to offer into the RPM Auction, in accordance with the PJM Manuals:

(i) whether or not the Generation Capacity Resource is receiving or expected to receive Conditioned State Support under any legislative or other governmental policy or program that has been enacted or effective at the time of the certification; and

(ii) whether or not the Capacity Market Seller acknowledges and understands that the Exercise of Buyer-Side Market Power is not permitted in RPM Auctions, and does not intend to submit a Sell Offer for their Generation Capacity Resource as an Exercise of Buyer-Side Market Power.

(B) All Capacity Market Sellers shall be responsible for the accuracy of each certification and its conformance with the Tariff irrespective of any guidance developed by the Office of the Interconnection and the Market Monitoring Unit.

(C) Once a Capacity Market Seller has certified whether or not a Generation Capacity Resource is receiving or expected to receive Conditioned State Support, the certification requirements in subsection (A)(i) above do not apply and the status of such Generation Capacity Resource will remain unchanged unless and until the Capacity Market Seller (or a subsequent Capacity Market Seller of the underlying resource) that owns or controls such Generation 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 Generation Capacity Resource's material change in status regarding whether such resource is receiving or expected to receive Conditioned State Support within 30 days of such material change. Nothing in this provision shall supersede the requirement for all Capacity Market Sellers to certify to the Office of Interconnection pursuant to Tariff, Attachment DD, section 5.14(h-2)(1)(A)(ii).

(2) **Determining Generation Capacity Resources Subject to the Minimum Offer Price Rule.**

(A) Conditioned State Support.

(i) If the Office of the Interconnection reasonably believes a government policy or program would provide Conditioned State Support or a Capacity Market Seller certifies that it is receiving or is expected to receive Conditioned State Support associated with a given Generation Capacity Resource, the Office of Interconnection shall submit, pursuant to section 205 of the Federal Power Act, 16 U.S.C. § 824d, a filing at FERC indicating the Office of the Interconnection's intent to classify the government policy or program from which that support is derived as Conditioned State Support (and adding such policy or program to the list in Tariff, Attachment DD-3) and apply the Minimum Offer Price Rule to each Generation Capacity Resource reasonably expected to receive such Conditioned State Support. If FERC has already ruled on whether a specific government program or policy constitutes Conditioned State Support and such policy or program is listed in Tariff, Attachment DD-3, the Office of the Interconnection shall not be required to submit the filing described in the preceding sentence.

(ii) Government policies or programs that do not provide payments or other financial benefit outside of PJM markets and do not provide payment or other financial benefit in exchange for the sale of a FERC-jurisdictional product conditioned on clearing in any RPM Auction do not constitute Conditioned State Support. Examples of such government policies that do not constitute Conditioned State Support may include, but are not limited to: policies designed to procure, incent, or require environmental attributes, whether bundled or unbundled (e.g., Renewable Energy Credits, Zero Emission Credits; Regional Greenhouse Gas Initiative); economic development programs and policies; tax incentives; state retail default service auctions; policies or programs that provide incentives related to fuel supplies; 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., Cross-State Air Pollution Rule). In addition, Conditioned State Support shall not be determined solely based on the business model of the Capacity Market Seller, such that the fact that a Self-Supply Entity is the Capacity Market Seller, for example, is not a basis for determining Conditioned State Support.

(iii) Upon FERC acceptance (whether by order or operation of law) that a government policy or program or contract with a state entity constitutes Conditioned State Support, a Generation Capacity Resource for which a Capacity Market Seller certifies pursuant to Tariff, Attachment DD, section 5.14(h-2)(1)(A)(i) that it is receiving Conditioned State Support or is reasonably expected to receive such Conditioned State Support, as identified by the Office of the Interconnection, with the advice and input of the Market Monitoring Unit, will be subject to the provisions of the Minimum Offer Price Rule.

(B) Exercise of Buyer-Side Market Power

(i) If a Capacity Market Seller does not certify that it acknowledges the prohibition of the Exercise of Buyer Side Market Power and the Capacity Market Seller intends to exercise Buyer-Side Market Power for this Generation Capacity Resource, then the underlying Capacity Resource shall be subject to the MOPR pursuant to Tariff, Attachment DD, section 5.14(h-2)(1)(A)(i). If the Office of the Interconnection and/or the Market Monitoring Unit reasonably suspects that a certification submitted under Tariff, Attachment DD, section 5.14(h-2)(1)(A)(ii) contains fraudulent or material misrepresentations such that the Capacity Market Seller's Generation Capacity Resource may be the subject of a Sell Offer that would be an Exercise of Buyer-Side Market Power or otherwise reasonably suspects that a Generation Capacity Resource may be the subject of a Sell Offer that would be an Exercise of Buyer-Side Market Power, the Office of the Interconnection and/or the Market Monitoring Unit shall initiate a fact-specific review into the facts and circumstances regarding the Generation Capacity Resource and whether the Capacity Market Seller has the ability and incentive to exercise Buyer-Side Market Power with respect to such Generation Capacity Resource. During such fact-specific review, the Capacity Market Seller will have the opportunity to explain and justify why a Sell Offer for the Generation Capacity Resource would not be an Exercise of Buyer-Side Market Power. The Office of the Interconnection and/or the Market Monitoring Unit shall notify the Capacity Market Seller of the bases for inquiry and initiation of review at least 135 days in advance of the RPM Auction conducted for the 2024/2025 Delivery Year and all subsequent Delivery Years, and by the date posted on the PJM website for the 2023/2024 Delivery Year.

In initiating a review, the Office of the Interconnection and/or the Market Monitoring Unit shall provide the affected Capacity Market Seller, in writing, the basis for its inquiry, including, but not limited to, the Generation Capacity Resource(s), and the purported beneficiary of any price suppression. The Office of the Interconnection and/or the Market Monitoring Unit may request from the Capacity Market Seller additional information and documentation that is reasonably related to the basis for its inquiry, provided that, the Office of the Interconnection and the Market Monitoring Unit shall confer with the Capacity Market Seller in advance of any such requests. The Capacity Market Seller shall provide any additional supporting information and documentation requested by the Office of the Interconnection and/or the Market Monitoring Unit, and any other information and documentation the Capacity Market Seller believes may justify the conduct or action in question as not representing an Exercise of Buyer-Side Market Power, within 15 days or other such timeline as agreed to in writing by the Office of the Interconnection, Market Monitoring Unit and Capacity Market Seller.

The fact-specific review will determine, as necessary, whether a Capacity Market Seller has the ability and incentive to submit a Sell Offer for the Generation Capacity Resource that could be an Exercise of Buyer-Side Market Power, as follows:

(a) To determine whether a Capacity Market Seller may have Buyer Side Market Power associated with the Generation Capacity Resource for the applicable RPM Auction, the Office of the Interconnection and/or the Market Monitoring Unit will perform ex-ante testing to determine the extent to which a shift in the supply curve by a number of megawatts equal to the size of the Generation Capacity Resource would affect RPM Auction clearing prices, where such analysis would reflect expected supply and demand conditions in the region of the market clearing prices and quantities in recent RPM Auctions, would reflect whether the relevant LDAs have been constrained in recent RPM Auctions, and would reflect reasonably expected material changes in an LDA including the modeling of the LDA and expected changes in supply and demand for the applicable Delivery Year. To the extent the foregoing analyses show that the Generation Capacity Resource would have a material effect on RPM Auction clearing prices, the Capacity Market Seller shall be deemed to have the ability to exercise Buyer Side Market Power.

(b) To determine whether the Capacity Market Seller's submission of a Sell Offer at any given price level for such Generation Capacity Resource may constitute an Exercise of Buyer-Side Market Power, the Office of the Interconnection and/or the Market Monitoring Unit shall perform ex-ante testing to determine whether, given the ability to suppress prices identified in the relevant LDAs and the PJM Region, such price suppression would be economically beneficial to the Capacity Market Seller by comparing its expected cost with its economic benefit, and where the expected cost shall reflect the excess economic costs of the resource above expected market revenues, and the expected benefit shall reflect the expected cost savings to the expected net short position (based on estimated capacity obligations and owned and contracted capacity measured on a three-year average basis for the three years starting with the first day of the Delivery Year associated with the RPM Auction in which the Generation Capacity Resource is being offered) in the relevant LDAs and RTO multiplied by the price change resulting from offering the resource uneconomically. In this analysis, the Office of Interconnection and/or the Market Monitoring Unit shall consider whether any capacity obligations in which the capacity costs based on RPM Auction clearing prices are directly passed through to load and consider whether the price of any contracted capacity passes through RPM Auction clearing prices. If the expected benefit outweighs the expected cost, the Capacity Market Seller shall be deemed to have the incentive to exercise Buyer Side Market Power. If a resource offer can be justified, economically or otherwise, without consideration of the benefit to the Capacity Market Seller of the suppressed prices, the Capacity Market Seller shall be deemed not to have the incentive to exercise Buyer Side Market Power with respect to that resource. Out-of-market compensation (such as from renewable energy credits and zero emission credits) that are not tied to either Conditioned State Support or a bilateral contract that directs the submission of an offer to lower market clearing prices may be used to support the economics of the resource under review.

(ii) The following nonexhaustive list of circumstances would preclude an inquiry into or determination regarding an Exercise of Buyer-Side Market Power in the course of a review initiated pursuant to subsection (i) above: (a) the Generation Capacity Resource is a merchant generation supply resources that is not contracted to an entity with a Load Interest; (b) the Generation Capacity Resource is acquired by or under the contractual control of the Capacity Market Seller through a competitive and non-discriminatory procurement process open to new and existing resources; or (c) the Generation Capacity Resource is owned by or bilaterally contracted to a Self-Supply Seller and such resource is demonstrated as consistent with or included in the Self-Supply Seller's long-range resource plan (e.g., a long-range hedging plan) that is approved or otherwise reviewed and accepted by the RERRA, provided that any such plan approval or contracts do not direct the submission of an uneconomic offer to deliberately lower market clearing prices or for the Capacity Market Seller to otherwise perform an Exercise of Buyer-Side Market Power. In addition, to the extent a Generation Capacity Resource may receive compensation in support of characteristics aligned with well-demonstrated customer preferences, such compensation shall not, in and of itself, be a basis for the determination of Buyer-Side Market Power.

(iii) Based on the foregoing tests and fact-specific review, including the facts and circumstances of the Generation Capacity Resource, the Office of the Interconnection, with the advice and input of the Market Monitoring Unit, shall determine whether a Generation Capacity Resource may be the subject of a Sell Offer that would be an Exercise of Buyer-Side Market Power. If the Office of the Interconnection, with the advice and input of the Market Monitoring Unit, determines that a Generation Capacity Resource may be the subject of a Sell Offer that would be an Exercise of Buyer-Side Market Power or the Capacity Market Seller certifies that it intends to exercise Buyer-Side Market Power, then such resource will be subject to the provisions of the Minimum Offer Price Rule. If the resource will be subject to the provisions of the Minimum Offer Price Rule, the Office of the Interconnection shall include in the notice a written explanation for such determination. A Capacity Market Seller that is dissatisfied with the Office of the Interconnection's determination of whether a given Generation Capacity Resource is subject to the Minimum Offer Price Rule -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 its determination hereunder unless FERC by order directs otherwise.

(C) Failure to timely submit a certification. -Any Generation Capacity Resource for which a Capacity Market Seller has not timely submitted the certifications required under Tariff, Attachment DD, section 5.14(h-2)(1) shall be subject to the provisions of the Minimum Offer Price Rule. Notwithstanding the foregoing, if a Capacity Market Seller submits a timely unit-specific exception pursuant to Tariff, Attachment DD, section 5.14(h-2)(4) for the relevant Delivery Year, and PJM approves the unit-specific MOPR Floor Offer Price, then the Capacity Market Seller may use such floor price regardless of whether it timely submitted the foregoing certifications.

(3) **Minimum Offer Price Rule.** Any Sell Offer for a Generation Capacity Resource that is subject to the provisions of the Minimum Offer Price Rule pursuant to Tariff, Attachment DD, section 5.14(h-2)(2) shall have an offer price no lower than the applicable MOPR Floor Offer Price, unless the applicable MOPR Floor Offer Price is higher than the applicable Market Seller Offer Cap, in which circumstance the Capacity Market Seller, to participate in an RPM Auction, must request a unit-specific value determined in accordance with the unit-specific MOPR Floor Offer Price process, and the unit-specific MOPR Floor Offer Price shall establish the offer level for such resource.

(A) New Entry MOPR Floor Offer Price. For a Generation Capacity Resource that is subject to the provisions of the Minimum Offer Price Rule pursuant to Tariff, Attachment DD, section 5.14(h-2)(2) and for which a Sell Offer based on that resource, or any uprate of such Generation Capacity Resource participating in the generation interconnection process under Tariff, Part IV, Subpart A, that has not cleared an RPM Auction for any Delivery Year, the applicable MOPR Floor Offer Price, based on the net cost of new entry for the resource type, shall be, at the election of the Capacity Market Seller, (i) the unit-specific value determined in accordance with the unit-specific MOPR Floor Offer Price process in Tariff, Attachment DD, section 5.14(h-2)(4) 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 or 2026/2027 Delivery Year, as applicable, net of estimated net energy and ancillary service revenues for the resource type and Zone in which the resource is located.

Resource Type	**Through the 2025/2026 Delivery Years: Gross Cost of New Entry (2022/2023 $/ MW-day) (Nameplate)**	**For the 2026/2027 Delivery Year and Subsequent Delivery Years: Gross Cost of New Entry (2026/2027 $/ MW-day) (Nameplate)**
Nuclear	$2,000	$2,568
Coal	$1,068	$1,480
Combined Cycle	$320	$540
Combustion Turbine	$294	$427
Fixed Solar PV	$271	$298
Tracking Solar PV	$290	$321
Onshore Wind	$420	$438
Offshore Wind	$1,155	$1,351
Battery Energy Storage	$532	$502

The gross cost of new entry values in the table above are expressed in dollars per MW-day in terms of nameplate megawatts. For purposes of submitting a Sell Offer, the gross cost of new entry values must be converted to a net cost of new entry by subtracting the estimated net energy and ancillary service revenues, as determined below, from the gross cost of new entry. However, the resultant net cost of new entry of the battery energy storage resource type in the table above must be multiplied by 2.5. The net cost of new entry based on nameplate capacity is then converted to Unforced Capacity ("UCAP") MW-day. For the 2023/2024 Delivery Year and subsequent Delivery Years, to determine the applicable UCAP MW-day value, the net cost of new entry is adjusted as follows: for battery storage, wind, and solar resource types, the applicable ELCC Class Rating; or for all other generation resource types, the applicable class average EFORd. The resulting default New Entry MOPR Floor Offer price in UCAP/MW-day terms shall be applied to each MW offered for the Capacity Resource regardless of the actual Sell Offer quantity and regardless of whether the Sell Offer is for a Seasonal Capacity Performance Resource.

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 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, 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. Through the 2024/2025 Delivery Years, ~~T~~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, plus reactive 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; and

(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.

For the 2025/2026 Delivery Year and subsequent Delivery Years, the net energy and ancillary services revenue shall be the average of the net energy and ancillary services revenues that the resource is projected to receive from the PJM energy and ancillary service markets for the applicable Delivery Year from three separate simulations, with each such simulation using forward prices shaped using historical data from one of each of the three consecutive calendar years preceding the time of the determination for the RPM Auction to take account of year-to-year variability in such hourly shapes. Each net energy and ancillary services revenue simulation shall be conducted in accordance with the following and the PJM Manuals:

(ix) for nuclear resource type, the net energy and ancillary services revenue estimate for each Zone shall be determined by the gross energy market revenue determined by the product of [average annual day-ahead Forward Hourly LMPs for such Zone, 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 for the 2025/2026 Delivery Year, or starting with the 2026/2027 Delivery Year and subsequent Delivery Years, $7.99/MWh for a single unit plant or $7.74/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 reactive services revenue of $2,251/MW-year;

(x) for coal resource type, the net energy and ancillary services revenue estimate for each Zone shall be determined by the Projected EAS 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 for the 2025/2026 Delivery Year, or starting with the 2026/2027 Delivery Year and subsequent Delivery Years, $10.92/MWh) using day-ahead and real-time Forward Hourly LMPs for such Zone and Forward Hourly Ancillary Service Prices, and daily forecasted coal prices, as set forth in the PJM Manuals, plus reactive services revenue of $2,217/MW-year;

(xi) for the 2025/2026 Delivery Year, for combustion turbine resource type, the net energy and ancillary services revenue estimate for each Zone shall be determined by the Projected EAS Dispatch of a single General Electric Frame 7HA turbine with evaporating cooling, Selective Catalytic Reduction technology, with dual Fuel capability, with the heat rate assumed for the combustion turbine resource shall be 9,134 BTU/kWh, the variable operations and maintenance expenses for such resources, inclusive of Maintenance Adder costs, shall be $6.93/MWh, plus ancillary services revenue of $2,199/MW-year. Starting with the 2026/2027 Delivery Year and subsequent Delivery Years, for combustion turbine resource type, the net energy and ancillary services revenue estimate for each Zone shall be determined by the Projected EAS Dispatch of a single General Electric Frame 7HA.02 turbine with evaporating cooling, Selective Catalytic Reduction technology, with the heat rate assumed for the combustion turbine resource shall be 9,189 BTU/kWh, the variable operations and maintenance expenses for such resources, inclusive of Maintenance Adder costs, shall be $1.19/MWh, plus ancillary services revenue of $3,565/MW-year.

(xii) for combined cycle resource type, for the 2025/2026 Delivery Year, the net energy and ancillary services revenue estimate for each Zone 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 6,501 BTU/kwh, the variable operations and maintenance expenses for such resource, inclusive of Maintenance Adder costs, shall be $2.11/MWh, plus reactive services revenue of $3,350/MW-year. Starting with the 2026/2027 Delivery Year and subsequent Delivery Years, for combined cycle resource type, the net energy and ancillary services revenue estimate for each Zone shall be determined in a manner consistent with the methodology described in Tariff, Attachment DD, section 5.10(a)(v-1)(B) for the Reference Resource combined cycle.

(xiii) for solar PV resource type, the net energy and ancillary services revenue estimate for each Zone 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 Forward Hourly LMP for such Zone and applicable to such hour with this product summed across all of the hours of an annual period, plus reactive services revenue of $6,791/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;

(xiv) for onshore wind resource type, the net energy and ancillary services revenue estimate for each Zone 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 Forward Hourly LMP for such Zone applicable to such hour with this product summed across all of the hours of an annual period, plus reactive services revenue of $4,027/MW-year;

(xv) for offshore wind resource type, the net energy and ancillary services revenue estimate for each Zone shall be determined by the gross energy market revenue equal to the product of [the average annual real-time Forward Hourly LMP for such Zone times 8,760 hours times an assumed annual capacity factor of 45%], plus reactive services revenue of $4,027/MW-year;

(xvi) for Capacity Storage Resource, the net energy and ancillary services revenue estimate shall be estimated by the Projected EAS Dispatch of a 1 MW, 4MWh resource, with an 85% roundtrip efficiency, and assumed to be dispatched between 95% and 5% state of charge against day-ahead and real-time Forward Hourly LMPs for such Zone and Forward Hourly Ancillary Service Prices, plus reactive services revenue of $3,903/MW-year.

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. 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 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.

Any Generation Capacity Resource that is subject to the provisions of the Minimum Offer Price Rule pursuant to Tariff, Attachment DD, section 5.14(h-2)(2) and that has not previously cleared an RPM Auction for that or any prior Delivery Year and for which there is no default MOPR Floor Offer Price provided in accordance with this section, including hybrid resources, must seek a unit-specific value determined in accordance with the unit-specific MOPR Floor Offer Price process below to participate in an RPM Auction. Failure to obtain a unit-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.

(i) For a Generation Capacity Resource that is subject to the provisions of the Minimum Offer Price Rule pursuant to Tariff, Attachment DD, section 5.14(h-2)(2) and for which a Sell Offer based on that resource has previously cleared an RPM Auction for any Delivery Year, the applicable Cleared MOPR Floor Offer Price shall be, at the election of the Capacity Market Seller, (a) based on the unit-specific MOPR Floor Offer Price, as determined in accordance with Tariff, Attachment DD, section 5.14(h-2)(4) below, or (b) 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 or 2026/2027 Delivery Year, as applicable, to reflect changes in avoidable costs, net of projected PJM market revenues equal to, through the 2024/2025 Delivery Year, the resource's historical net energy and ancillary service revenues consistent with Tariff, Attachment DD, section 6.8(d), or starting with the 2025/2026 Delivery Year and subsequent Delivery Years, the resource's net energy and ancillary service revenues for the resource type, as determined in accordance with subsection (ii) below.

Existing Resource Type	Through the 2025/2026 Delivery Years: Default Gross ACR (2022/2023) ($/MW-day) (Nameplate)	For the 2026/2027 Delivery Year and Subsequent Delivery Years: Default Gross ACR (2026/2027) ($/ MW-day) Nameplate
Nuclear - single	$697	$591
Nuclear - dual	$445	$537
Coal	$80	$94
Combined Cycle	$56	$113
Combustion Turbine	$50	$52
Steam Oil & Gas	NA	$64
Solar PV (fixed and tracking)	$40	$70
Wind Onshore	$83	$147

The default gross Avoidable Cost Rate values in the table above are expressed in dollars per MW-day in terms of nameplate megawatts. For purposes of submitting a Sell Offer, the default Avoidable Cost Rate values must be net of estimated net energy and ancillary service revenues, and then the difference is ultimately converted to Unforced Capacity ("UCAP") MW-day, where the UCAP MW-day value will be determined based on the 2023/2024 Delivery Year and subsequent Delivery Years, the resource-specific Accredited UCAP value for solar and wind resource types (with appropriate time-weighting for any winter Capacity Interconnection Rights) or the resource-specific EFORd for all other generation resource types and on. The resulting default Cleared MOPR Floor Offer price in UCAP/MW-day terms shall be applied to each MW offered for the Capacity Resource regardless of actual Sell Offer quantity and regardless of whether the Sell Offer is for a Seasonal Capacity Performance Resource.

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. Updated estimates of the net energy and ancillary service revenues shall be determined on a resource-specific basis in accordance with Tariff, Attachment DD, section 6.8(d) 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 Resource that is subject to the provisions of the Minimum Offer Price Rule pursuant to Tariff, Attachment DD, section 5.14(h-2)(2) that have cleared in an RPM Auction for any 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.

Any Generation Capacity Resource that is subject to the provisions of the Minimum Offer Price Rule pursuant to Tariff, Attachment DD, section 5.14(h-2)(2) and that has previously cleared an RPM Auction for any Delivery Year and for which there is no default MOPR Floor Offer Price provided in accordance with this section, including hybrid resources, must seek a unit-specific value determined in accordance with the unit-specific MOPR Floor Offer Price process below to participate in an RPM Auction. Failure to obtain a unit-specific MOPR Floor Offer Price will result in the Office of the Interconnection rejecting any Sell Offer based on such resource.

(ii) Effective with the 2025/2026 Delivery Year and subsequent Delivery Years, the net energy and ancillary services revenue is equal to forecasted net revenues which shall be determined in accordance with the applicable resource type net energy and ancillary services revenue determination methodology set forth in Tariff, Attachment DD, section 5.14(h-2)(2)(A)(ix) through (xvi) and using the subject resource's operating parameters as determined in accordance with the PJM Manuals based on (a) offers submitted in the Day-ahead Energy Market and Real-time Energy Market over the calendar year preceding the time of the determination for the RPM Auction; (b) the resource-specific operating parameters approved, as applicable, in accordance with Operating Agreement, Schedule 1, section 6.6(b) and Operating Agreement, Schedule 2 (including any Fuel Costs, emissions costs, Maintenance Adders, and Operating Costs); (c) the resource's Accredited UCAP Factor; (d) Forward Hourly LMPs at the generation bus as determined in accordance with Tariff, Attachment DD, section 5.10(a)(v-1)(C)(6); and (e) the resource's stated annual revenue requirement for reactive services; plus any unit-specific bilateral contract. In addition, the following resource type-specific parameters shall be considered; (f) for combustion turbine, combined cycle, and coal resource types: the installed capacity rating, ramp rate (which shall be equal to the maximum ramp rate included in the resource's energy offers over the most recent previous calendar year preceding the determination for the RPM Auction), and the heat rate as determined as the resource's average heat rate at full load as submitted to the Market Monitoring Unit and the Office of the Interconnection, where for combined cycle resources heat rates will be determined at base load and at peak load (e.g., without duct burners and with duct burners), as applicable; (g) for nuclear resource type: anticipated refueling schedule; (h) for solar and wind resource types: the resource's output profiles for the most recent three calendar years, as available; and (i) for battery storage resource type: the nameplate capacity rating (on a MW / MWh basis).

To the extent the resource has not achieved commercial operation, the operating parameters used in the simulation of the net energy and ancillary service revenues will be based on the manufacturer's specifications and/or from parameters used for other existing, comparable resources, as developed by the Market Monitoring Unit and the Capacity Market Seller, and accepted by the Office of the Interconnection.

A Capacity Market Seller intending to submit a Sell Offer in any RPM Auction for a Cleared Capacity Resource with State Subsidy based on a net energy and ancillary services revenue determination that does not use the foregoing methodology or parameter inputs stated for that resource type shall, at its election, submit a request for a resource-specific MOPR Floor Offer Price for such Capacity Resource pursuant to Tariff, Attachment DD, section 5.14(h-2)(3) below

(4) **Unit-Specific Exception**. A Capacity Market Seller intending to submit a Sell Offer in any RPM Auction for a Generation Capacity Resource that is subject to the provisions of the Minimum Offer Price Rule below the applicable default MOPR Floor Offer Price may, at its election, submit a request for a unit-specific exception for such Capacity Resource. A Capacity Market Seller intending to submit a Sell Offer in any RPM Auction for a Generation Capacity Resource that is under a fact-specific review for Buyer-Side Market Power pursuant to Tariff, Attachment DD, section 5.14(h-2)(2)(B)(ii), and where the offer is below the applicable default MOPR Floor Offer Price may, at its election, submit a request for a unit-specific exception for such Generation Capacity Resource. A Sell Offer below the default MOPR Floor Offer Price, but no lower than the unit-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. The unit-specific MOPR Floor Offer Price determined under this provision shall be based on the unit-specific Accredited UCAP value for battery energy storage resource types and for solar and wind generation resource types (appropriately time-weighted for any winter Capacity Interconnection Rights) or on the unit-specific EFORd for all other generation resource types, and shall be applied to each MW offered by the resource regardless of actual Sell Offer quantity and regardless of whether the Sell Offer is for a Seasonal Capacity Performance Resource. Such Sell Offer is permissible because it is consistent with the competitive, cost-based, fixed, net cost of the resource. 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 unit-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)(3)(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 unit-specific exception for a Generation Capacity Resource that is subject to the provisions of the Minimum Offer Price Rule pursuant to Tariff, Attachment DD, section 5.14(h-2)(2) and that has never cleared an RPM Auction, 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 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 or any other revenues outside of PJM markets that do not constitute Conditioned State Support), 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 unit-specific exception hereunder. The request also shall identify all revenue sources (exclusive of any Conditioned State Support or bilateral contracts that direct submission of an offer to lower RPM Auction clearing prices) relied upon in the Sell Offer to offset the claimed fixed costs, including, without limitation, long-term power supply contracts, tolling agreements, evidence of compensation outside the PJM market not tied to Conditioned State Support or a bilateral contract that directs submission of an offer to lower RPM Auction clearing prices, 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. Through the 2024/2025 Delivery Year, ~~I~~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, which may include Maintenance Adders, 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. Starting with the 2025/2026 Delivery Year and subsequent Delivery Years, in making such demonstration, the Capacity Market Seller may rely upon revenues projected by well-defined, forward-looking dispatch models designed to generally follow the rules and processes of PJM's energy and ancillary services market. Such models must utilize publicly available forward prices for electricity and fuel in the PJM Region. Any modifications made to the forward electricity and fuel prices must similarly use publicly available data. Alternative forward prices for fuel may be used if accompanied by contractual evidence showing the applicability of the alternative fuel price. Where forward fuel markets are not available, publicly available estimates of future fuel prices may be used. The model shall also contain estimates of, variable operation and maintenance expenses, which may include Maintenance Adders, and emissions allowance prices. Documentation for net revenues also must 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, capacity factors, 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 the alternative, the Capacity Market Seller may request that the Market Monitoring Unit, subject to acceptance by the Office of Interconnection, produce a resource-specific Energy & Ancillary Services Offset value for such resource using the Forward Hourly LMPs, Forward Hourly Ancillary Service Prices and either Forward Daily Natural Gas Prices for combustion turbines and combined cycle resources, or forecasted fuel prices for other resource types, plus plant parameters and capability information specific to the dispatch of the resource, as outlined above. 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.

(C) Through the 2024/2025 Delivery Years, ~~F~~for a Unit-Specific Exception for a Generation Capacity Resource that is subject to the provisions of the Minimum Offer Price Rule pursuant to Tariff, Attachment DD, section 5.14(h-2)(2) and that has previously cleared an RPM Auction, 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 Conditioned State Support or bilateral contracts that direct submission of an offer to lower RPM Auction clearing prices) relied upon in the Sell Offer to offset the claimed fixed costs, including, without limitation, long-term power supply contracts, tolling agreements, evidence of compensation outside of PJM markets not tied to Conditioned State Support or a bilateral contract that directs submission of an offer to lower RPM Auction clearing prices, 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, which may include Maintenance Adders, and 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.

(C-1) Beginning with the 2025/2026 Delivery Year and subsequent Delivery Years, for a Unit-Specific Exception for a Generation Capacity Resource that is subject to the provisions of the Minimum Offer Price Rule pursuant to Tariff, Attachment DD, section 5.14(h-2)(2) and that has previously cleared an RPM Auction, 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 shall, 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 Conditioned State Support or bilateral contracts that direct submission of an offer to lower RPM Auction clearing prices) relied upon in the Sell Offer to offset the claimed fixed costs, including, without limitation, long-term power supply contracts, tolling agreements, evidence of compensation outside of PJM markets not tied to Conditioned State Support or a bilateral contract that directs submission of an offer to lower RPM Auction clearing prices, 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 revenues projected by well-defined, forward-looking dispatch models designed to generally follow the rules and processes of PJM's energy and ancillary services market. Such models must utilize publicly available forward prices for electricity and fuel in the PJM Region. Any modifications made to the forward electricity and fuel prices must similarly use publicly available data. Alternative forward prices for fuel may be used if accompanied by contractual evidence showing the applicability of the alternative fuel price. Where forward fuel markets are not available, publicly available estimates of future fuel sources may be used. The model shall also contain estimates of variable operation and maintenance expenses, which may include Maintenance Adders, and emissions allowance prices. Documentation for net revenues also must 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, capacity factors, 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.

In the alternative, the Capacity Market Seller may request that the Market Monitoring Unit, subject to acceptance by the Office of Interconnection, produce a resource-specific projected energy and ancillary services markets revenues for such resource using the Forward Hourly LMPs, Forward Hourly Ancillary Service Prices and either Forward Daily Natural Gas Prices for combustion turbines and combined cycle resources, or forecasted fuel prices for other resource types, plus plant parameters and capability information specific to the dispatch of the resource, as outlined above. 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.

(D) A Sell Offer evaluated at the unit-specific exception shall be permitted if the information provided reasonably demonstrates that the Sell Offer's competitive, fixed, cost-based offer level 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, and that out-of-market compensation is not tied to Conditioned State Support or a bilateral contract that directs submission of an offer to lower RPM Auction clearing prices. Failure to adequately support such claimed cost advantages or revenues so as to enable the Office of the Interconnection to make the determination required in this section will result in the elimination of consideration of the unsupported element(s) of a unit-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 unit-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 unit-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 unit-specific determination unless and until ordered to do otherwise by FERC.

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) above also shall receive a credit, comparable to the Capacity Transfer Rights provided to Load-Serving Entities under Tariff, Attachment DD, section 5.15. Such credit shall be equal to the locational capacity price difference specified in section 5.14(i)(1) above 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.

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. A Capacity Market Seller offering above $0/MW-day must support and obtain approval of a unit-specific Market Seller Offer Cap pursuant to the procedures and standards of subsection (b) of this section 6.4 or may, at its election, if available, utilize a Market Seller Offer Cap determined using the applicable default gross Avoidable Cost Rate for the applicable resource type shown in the table below, as adjusted for Delivery Years subsequent to the 2022/2023 or 2026/2027 Delivery Year, as applicable, to reflect changes in avoidable costs, net of *Projected* PJM *Market Revenues* equal to the resource's net energy and ancillary service revenues for the resource type, as determined in accordance with Tariff, Attachment DD, section 6.8(d).

Existing Resource Type	Through the 2025/2026 Delivery Years: Default Gross ACR (2022/2023) ($/MW-day) (Nameplate)	For the 2026/2027 Delivery Year and Subsequent Delivery Years: Default Gross ACR (2026/2027) ($/MW-day) (Nameplate)
Nuclear – single	$697	$591
Nuclear – dual	$445	$537
Coal	$80	$94
Combined Cycle	$56	$113
Combustion Turbine	$50	$52
Steam Oil & Gas	NA	$64
Solar PV (fixed and tracking)	$40	$70
Wind Onshore	$83	$147

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.

(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, or calculate an alternative unit-specific Market Seller Offer Cap based on the submitted documentation, 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. In the event the Office of the Interconnection rejects the Capacity Market Seller's requested unit-specific Market Seller Offer Cap for a particular Existing Generation Capacity Resource, the Capacity Market Seller of such Capacity Resource may submit an offer up to (1) should one exist, the default gross Avoidable Cost Rate for the applicable resource type net of *Projected* PJM *Market Revenues* equal to the resource's net energy and ancillary service revenues for the resource type, or (2) the unit-specific Market Seller Offer Cap proposed by the Market Monitoring Unit upon PJM approval of such value, or (3) an alternative unit-specific Market Seller Offer Cap calculated by the Office of the Interconnection based on the submitted documentation. 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 6.4(a) above.

Notwithstanding the provisions of Tariff, Attachment M-Appendix, section II.E.2 and this Tariff, Attachment DD, section 6.4(b), no later than eighty (80) days prior to the commencement of the offer period for the auction, the Market Monitoring Unit and the relevant Capacity Market Seller may mutually agree on the value of such Market Seller Offer Cap. Nothing herein shall preclude the Market Monitoring Unit from modifying the Market Seller Offer Cap for a Generation Capacity Resource beyond the eighty-day (80-day) deadline prior to the commencement of the offer period for the auction, through the commencement of the offer period for the auction, so long as the Market Monitoring Unit and the relevant Capacity Market Seller mutually agree with the value of such Market Seller Offer Cap. The Capacity Market Seller shall notify the Market Monitoring Unit in writing, with a copy to the Office of the Interconnection, if such an agreement with the Market Monitoring Unit has been reached. The Office of the Interconnection shall review the Market Seller Offer Cap submitted by the Capacity Market Seller and make a determination whether the Market Seller Offer Cap complies with the tariff, and notify the Capacity Market Seller and the Market Monitoring Unit of its determination.

(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 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 1.1 times the Capacity Resource Clearing Price in the Base Residual Auction for the relevant LDA and Delivery Year.

(e) Effective with the 2025/2026 Delivery Year, Capacity Market Sellers that submit a unit-specific Market Seller Offer Cap by the deadline may request to use and provide support for a segmented offer cap to reflect incremental costs of having a capacity obligation across different segments of their unit. Such request must provide adequate justification for the use of a segmented offer cap with supporting documentation and calculations for the Market Seller Offer Cap of each segment. Segmented Market Seller Offer Caps shall be comprised of multiple Market Seller Offer Caps, each calculated in accordance with Tariff, Attachment DD, section 6.8. If elected by the Capacity Market Seller, the first segment may have a Market Seller Offer Cap reflective of incremental expenses directly required to operate a Generation Capacity Resource that a Generation Owner would not incur if such generating unit were to mothball or retire, in accordance with Tariff, Attachment DD, section 6.8(b). All other offer segments (and, if elected by the Capacity Market Seller, the first segment) shall reflect incremental costs that would be avoided only in the absence of a capacity obligation, in accordance with Tariff, Attachment DD, section 6.8(b).

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 $0/MW-day, except as described in Tariff, Attachment DD, section 6.4(a); 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 Market Seller Offer Cap.

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~~ 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 default Net CONE value for the applicable technology, as calculated in accordance with Tariff, Attachment DD, section 5.14(h-2)(A), ~~applicable~~ for such Delivery Year in the ~~LDA~~ Zone for which such Sell Offer was submitted; or 2) if there is no default Net CONE value for the applicable technology for such Delivery Year in the Zone, the Net CONE that is used in setting the VRR Curve applicable for such Delivery Year in the LDA for which such Sell Offer was submitted. Notwithstanding the above, the Sell Offer of a Planned Generation Capacity Resource shall not be rejected if offered at or below a unit-specific offer price that is calculated in accordance with Tariff, Attachment DD, section 5.14(h-2)(4)(B), and submitted and approved in accordance with Tariff, Attachment DD, section 6.4(b). ~~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.

6.7 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 above $0/MW-day, except as 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, if applicable, 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 E/Siemens~~	~~$39.06~~	~~$52.89~~	~~$40.57~~	~~$54.94~~	~~$42.23~~	~~$57.18~~	~~$39.75~~	~~$53.83~~
~~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 in Tariff, Attachment DD, section 6.8~~below~~ and applied to the unit's Base Offer Segment. For determining the costs that are avoidable in the unit-specific Avoidable Cost Rate, Capacity Market Sellers shall indicate if the resource will mothball or retire if not cleared in the capacity market, or if the resource shall continue operating and participate in the energy and ancillary services markets during the Delivery Year if not cleared. Capacity Market Sellers that indicate a decision to mothball or retire the resource if not cleared, and use that as the basis for the unit's avoidable costs, shall be required to provide an officer certification. Should the resource not clear in the capacity market and there is a change in the decision to mothball or retire the resource, the Office of the Interconnection and/or the Market Monitoring Unit may require the Capacity Market Seller to provide support for such change.

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, retaining, or

otherwise managing the risks of ~~n~~Non-~~p~~Performance Charges 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 quotes or expected 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. CPQR shall also be considered reasonably supported if a Capacity Market Seller provides supporting documentation, along with an officer certification, that their risk model, inputs, and costs of CPQR have undergone a review by an independent third party entity with experience in evaluating capacity performance insurance policies to confirm that the proposed valuation of risk is consistent with actuarial practices in the industry. 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.

Notwithstanding the above, a CPQR shall be considered reasonably supported when calculated based on the following formula: Risk Cost multiplied by Extreme Value, where:

- Risk Cost reflects an estimated cost of managing the risks of Non-Performance Charges, and by default, shall equal the after tax Weighted Average Cost of Capital (calculated as: percent equity * cost of equity + percent debt * debt interest rate * (1- effective tax rate)), which shall be determined in a manner consistent with the calculated value used in the CRF formula in the APIR component. A Capacity Market Seller that submits a unit-specific Market Seller Offer Cap may substitute their own estimate of Risk Cost with supporting documentation.

- Extreme Value is the annual total net Non-Performance Charges for the resource at a pre-determined confidence interval (i.e. 95th percentile), based on a probabilistic analysis conducted by the Office of the Interconnection that models the resource's performance under a range of simulated system conditions to measure the distribution of potential annual total net over- and under-performance of the resource, along with the annual total net non-performance charges and bonus credits during the simulated Performance Assessment Intervals in the analysis.

- **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, applied in accordance with the terms specified below. CRF values are calculated for recovery periods of 4, 5, 10, 15, 20, 25, and 30 years, using the following formula with assumptions of the following components: (i) capital structure and cost of capital; (ii) debt interest rate; (iii) state income tax rate, and (iv) federal income tax and depreciation rates as utilized by the U.S. Internal Revenue Service.

$$\mathrm{CRF} = \frac{r(1+r)^N\left[1 - \frac{sB}{\sqrt{1+r}} - s(1-B)\sqrt{1+r}\sum_{j=1}^{L}\frac{m_j}{(1+r)^j}\right]}{(1-s)\sqrt{1+r}\,[(1+r)^N - 1]}$$

Where:
r is the after tax Weighted Average Cost of Capital (calculated as: percent equity * cost of equity + percent debt * debt interest rate * (1- effective tax rate))
s is the effective tax rate (calculated as: State Tax Rate + Federal Tax Rate*(1-State Tax Rate))
B is the bonus depreciation percent
N is the cost recovery period (years)
L is the lessor of N or 16 (years)
m_j is the modified accelerated cost recovery system (MACRS) depreciation factor for year j =1, . . ., 16.

The CRF values of the following table shall be used for RPM Auctions through and including the Base Residual Auction conducted for 2022/2023 Delivery Year. Thereafter, the table of CRF values applicable to each RPM Auction shall be determined and posted on the PJM website by no later than 150 days prior to the commencement of the offer period of the RPM Auction. The values of the posted CRF table shall be determined using federal income tax laws in effect at the time of the determination for the relevant Delivery Year and shall use the same assumptions of (i) capital structure and cost of capital; (ii) debt interest rate; and (iii) state income tax rate, as those utilized to calculate the Cost of New Entry for the Reference Resource for the relevant Delivery Year. For the purpose of the CRF determination, the state income tax rate will be set equal to the average state income tax rate used to calculate the Cost of New Entry of the Reference Resource across the four CONE Regions. The CRF for the 40 Plus Alternative option shall be set equal to 1.1 and is not calculated by the formula above.

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 or posted 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 or posted 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 were to mothball or retire and did not operate or have a capacity obligation in the Delivery Year ~~or meet Availability criteria during Peak-Hour Periods during the Delivery Year~~. Alternatively, for Capacity Market Sellers that have indicated in their submission of a unit-specific Market Seller Offer Cap that the resource will continue to operate and participate in the energy and ancillary services markets during the Delivery Year if not cleared in the capacity market, avoidable costs and expenses shall be limited to the incremental costs that would be avoided only in the absence of a capacity obligation such as CPQR. Such Capacity Market Sellers of resources that will continue to operate and participate in the energy and ancillary services markets shall not include labor, maintenance, and other operating expenses that would be avoided only if the Capacity Resource were not operating and participating in the energy and ancillary services markets 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) For Delivery Years up to and including the 2024~~1~~/2025~~2~~ Delivery Year~~ and for the 2023/2024 Delivery Year and subsequent Delivery Years~~, 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 Agreement 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.

(d-1) ~~For the ~~Effective with the 202~~2~~5/202~~3~~6 and subsequent Delivery Years, Projected PJM Market Revenues for any Generation Capacity Resource to which the Avoidable Cost Rate is applied shall be equal to forecasted net revenues, which shall be determined in accordance with Tariff, Attachment DD, section 5.14(h-2~~1~~)(2)(B)(ii), or for resource types not specified in such section, in a manner consistent with the methodologies described in such section, that utilizes Forward Hourly LMPs and Forward Hourly Ancillary Service Prices for such resource, forecasted fuel prices as applicable, as well as resource-specific operating parameters and capability information specific to the simulated dispatch of such resource, where such dispatch shall either consider the hourly output profiles for Intermittent Resources in a manner consistent with solar and onshore wind methodologies, or utilize the Projected EAS Dispatch. To the extent the resource has achieved commercial operation, the dispatch shall utilize the resource-specific operating parameters as determined in accordance with the PJM Manuals based on offers submitted in the Day-ahead Energy Market and Real-time Energy Market, as well as the operating parameters approved, as applicable, in accordance with Operating Agreement, Schedule 1, section 6.6(b) and Operating Agreement, Schedule 2 (including any Fuel Costs, emissions costs, Maintenance Adders, and Operating Costs). Adjustments to resource-specific operating parameters may be submitted to the Market Monitoring Unit and the Office of the Interconnection for review and consideration in the simulated dispatch with supporting documentation. For resources that have not yet achieved commercial operation, the operating parameters used in the simulation of the net energy and ancillary service revenues will be based on the manufacturer's specifications and/or from parameters used for other existing, comparable resources, as developed by the Market Monitoring Unit and the Capacity Market Seller, and accepted by the Office of the Interconnection.

In the alternative, the Capacity Market Seller may provide their own estimate of Projected PJM Market Revenues to the Market Monitoring Unit and the Office of the Interconnection for review and approval. Such a request shall identify all revenue sources (exclusive of any State Subsidies), 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 standards prescribed above. In making such demonstration, the Capacity Market Seller may rely upon revenues projected by well-defined, forward-looking dispatch models designed to generally follow the rules and processes of PJM's energy and ancillary services markets. Such models must utilize forward prices for energy, ancillary service and fuel in the PJM Region based on contractual evidence of an alternative fuel price or sourced from liquid forward markets (where available), and other publicly available data to develop the forward prices used in the estimate. Where forward fuel markets are not available, publicly available estimates of future fuel sources may be used. The model shall also contain estimates of variable operation and maintenance expenses, which may include Maintenance Adders, and emissions allowance prices. Documentation for net revenues also must 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, capacity factors, 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.

Notwithstanding the foregoing, in the case that the Capacity Market Seller has indicated in their submission of a unit-specific Market Seller Offer Cap that the resource will continue to operate and participate in the energy and ancillary services markets during the Delivery Year if not cleared in the capacity market, the Projected PJM Market Revenues shall be zero dollars.

10A. CHARGES FOR NON-PERFORMANCE AND CREDITS FOR PERFORMANCE

(a) ~~For the 2018/2019 Delivery Year and any subsequent Delivery Year (and for certain purposes for the 2016/2017 and 2017/2018 Delivery Years as provided in subsections (h) and (i) hereof), e~~Each Capacity Market Seller that commits a Capacity Resource for a Delivery Year (whether through an RPM Auction, a bilateral transaction, or as Locational UCAP), each Locational UCAP Seller that sells Locational UCAP from a Capacity Resource for a Delivery Year, ~~and for the 2022/2023 Delivery Year and subsequent Delivery Years~~ each PRD Provider that commits Price Responsive Demand for a Delivery Year, shall be charged to the extent the performance of each of its committed Capacity Resources or Price Responsive Demand during all or any part of a clock-hour when an Emergency Action is in effect falls short of the expected performance of such resources (as determined herein) and the revenue from such charges shall be provided to Market Participants with generation, demand response resources, or Price Responsive Demand that perform during such hour in excess of the level expected based on commitments (if any) of such resources; provided, however, for the 2025/2026 Delivery Year and subsequent Delivery Years, the revenue from such charges shall be provided to Market Participants with committed Generation Capacity Resources in accordance with this Tariff, Attachment DD, section 10A(g).

(b) Performance shall be measured for purposes of this assessment during each Performance Assessment Interval.

(c) For each Performance Assessment Interval, the Office of the Interconnection shall determine whether, and the extent to which, the actual performance of each Capacity Resource, ~~and~~ Locational UCAP, and Price Responsive Demand has fallen short of the performance expected of such committed Capacity Resource or Price Responsive Demand, and the magnitude of any such shortfall, based on the following formula, and as further detailed in the PJM Manuals:

Performance Shortfall = Expected Performance - Actual Performance

Where the result of such formula is a positive number and where:
Expected Performance =

for Generation Capacity Resources (including external Generation Capacity Resources for any Performance Assessment Interval for which performance by such external resource would have helped resolve a declared Emergency Action); ~~provided, however, that for any Delivery Year up to and including the 2019/2020 Delivery Year, performance of external Generation Capacity Resources shall be assessed only during Performance Assessment Hours for Emergency Actions declared for the entire PJM Region)~~ and Capacity Storage Resources: [(Resource Committed Capacity * the Balancing Ratio)];

where

Resource Committed Capacity = the total megawatts of Unforced Capacity of the Capacity Resource committed by such Capacity Market Seller or Locational UCAP Seller; and

The Balancing Ratio = (All Actual Generation Performance, Storage Resource Performance, Net Energy Imports, Price Responsive Demand Bonus Performance ~~effective with the 2022/2023 Delivery Year~~, and Demand Response Bonus Performance) / (All Committed Generation and Storage Capacity); provided, however, that Net Energy Imports shall be included in the calculation of the Balancing Ratio only for any Performance Assessment Interval for which performance by any external Generation Capacity Resource would have helped resolve the Emergency Action that was the subject to the Performance Assessment ~~Hour~~Interval;~~ and provided further that for any Delivery Year up to and including the 2019/2020 Delivery Year, Net Energy Imports shall be included in the calculation of the Balancing Ratio only for any Performance Assessment Hour for which the Emergency Action was declared for the entire PJM Region; and~~ and provided further that effective with the 2025/2026 Delivery Year and subsequent Delivery Years, the Balancing Ratio shall solely include the actual performance of committed Generation Capacity and Storage Resources, and shall exclude the megawatts of committed Generation and Storage Capacity Resources that are not considered in the calculation of a Performance Shortfall for a Performance Assessment Interval pursuant to subsection (d-1) below; and provided further that the Balancing Ratio shall not exceed a value of 1.0.

for purposes of which

All Committed Generation and Storage Capacity = the total megawatts of Unforced Capacity of all Generation Capacity Resources (including external Generation Capacity Resources for any Performance Assessment Interval for which performance by such external resource would have helped resolve the declared Emergency Action that was the subject to the Performance Assessment ~~Hour~~Interval); ~~provided, however, that for any Delivery Year up to and including the 2019/2020 Delivery Year, performance of external Generation Capacity Resources shall be assessed only during Performance Assessment Hours for Emergency Actions declared for the entire PJM Region)~~ and all Capacity Storage Resources committed by all Capacity Market Sellers, FRR Entities, Locational UCAP Sellers;

All Actual Generation Performance and Storage Resource Performance = through the 2024/2025 Delivery Year, the total amount of Actual Performance for all generation resources (including external Generation Capacity Resources for any Performance Assessment Interval for which performance by such external resource would have helped resolve the declared Emergency Action that was the subject to the Performance Assessment ~~Hour~~Interval; provided, however, that for the 2025/2026 Delivery Year and subsequent Delivery Years, the Actual Performance shall be limited to resources who hold a capacity commitment during the Performance Assessment Interval~~any Delivery Year up to and including the 2019/2020 Delivery Year, performance of external Generation Capacity Resources shall be assessed only during Performance Assessment Hours for Emergency~~

~~Actions declared for the entire PJM Region) and storage resources during the interval~~;

Net Energy Imports = through the 2024/2025 Delivery Year, the sum of interchange transactions importing energy into PJM (not including those associated with external Generation Capacity Resources and therefore included in All Actual Generation Performance) minus the sum of interchange transactions exporting energy out of PJM, but not less than zero. Beginning with the 2025/2026 Delivery Year, Net Energy Imports shall be zero;

Demand Response Bonus Performance = through the 2024/2025 Delivery Year, the sum of Bonus performance provided by Demand Response resources as calculated in (g) below. Beginning with the 2025/2026 Delivery Year, Demand Response Bonus Performance shall be zero;

Price Responsive Demand Bonus Performance = through the 2024/2025 Delivery Year, the sum of Bonus performance provided by Price Responsive Demand as calculated in (g) below. Beginning with the 2025/2026 Delivery Year, Price Responsive Demand Bonus Performance shall be zero;

and for Demand Resources, Energy Efficiency Resources, and Qualifying Transmission Upgrades: Resource Committed Capacity;

where

Resource Committed Capacity = the total megawatts of capacity committed from such Capacity Resource committed capacity without making any adjustment for the Forecast Pool Requirement, and beginning with the 2025/2026 Delivery Year, for Demand Resources, without making an adjustment for the applicable ELCC Class Rating;

and for PRD Provider: Price Responsive Demand Committed

where

Price Responsive Demand Committed = the Nominal PRD Value committed by the PRD Provider in the area defined by the Performance Assessment Interval, adjusted to account for any PRD registrations in such area that were not subject to compliance measurement.

and

Actual Performance =

for each generation resource, the metered output of energy delivered to PJM by such resource ~~plus~~and adjusted by the resource's real-time reserve or regulation assignment, if any, during the Performance Assessment Interval; provided, however, for the 2025/2026 Delivery Year and subsequent Delivery Years, Actual Performance shall not exceed the installed capacity commitment for the resource.

for each storage resource, the metered output of energy delivered to PJM by such resource ~~plus~~and adjusted by the resource's real-time reserve or regulation assignment, if any, during the Performance Assessment Interval; provided, however, for the 2025/2026 Delivery Year and subsequent Delivery Years, Actual Performance shall not exceed the installed capacity commitment for the resource.

for each Demand Resource, the demand response provided to PJM by such resource, ~~plus~~and adjusted by such resource's real-time reserve or regulation assignment, if any, during the Performance Assessment Interval, as established through the PJM demand response settlement procedure consistent with the standards specified in RAA, Schedule 6; provided, however, for the 2025/2026 Delivery Year and subsequent Delivery Years, Actual Performance shall not exceed the installed capacity commitment for the resource.

for each PRD Provider, the actual load reduction provided by the PRD Provider during a Performance Assessment Interval, determined in accordance with RAA, Schedule 6.1.N and the PJM Manuals; provided, however, for the 2025/2026 Delivery Year and subsequent Delivery Years, Actual Performance shall not exceed the installed capacity commitment for the resource.

for each Energy Efficiency Resource, the load reduction quantity approved by PJM subsequent to the pre-delivery year submittal of a post-installation measurement and verification report; provided, however, for the 2025/2026 Delivery Year and subsequent Delivery Years, Actual Performance shall not exceed the installed capacity commitment for the resource; and

for each Qualified Transmission Upgrade, the megawatt quantity cleared by such Qualified Transmission Upgrade if it is in service during the Performance Assessment Interval, and zero if it is not in service during such Performance Assessment Interval.

Such calculation shall encompass all resources and Price Responsive Demand located in the area defined by the Emergency Action; provided, however, that Performance Shortfall shall be calculated for external Generation Capacity Resources for any Performance Assessment Interval for which performance by such external resource would have helped resolve the declared Emergency Action that was the subject to the Performance Assessment ~~Hour~~Interval~~; provided, however, that for any Delivery Year up to and including the 2019/2020 Delivery Year, Performance Shortfall shall be calculated for external Generation Capacity Resources only during Performance Assessment Hours which the Emergency Action was declared for the entire PJM Region. At the start of the Delivery Year, PJM will inform the Capacity Market Seller of an external resource as to which Locational Deliverability Area it has been assigned~~. For purposes of this provision, Qualifying Transmission Upgrades shall be deemed to be located in the Locational

Deliverability Area into which such upgrade increased the Capacity Emergency Transfer Limit, and a Qualifying Transmission Upgrade shall be included in calculations of Expected Performance and Actual Performance only if, and to the extent that, the declared Emergency Action encompasses the Locational Deliverability Area into which such upgrade increased the Capacity Emergency Transfer Limit. The Performance Shortfall shall be calculated for each Performance Assessment Interval, and any committed Capacity Resource for which the above calculation produces a negative number for a Performance Assessment Interval shall not have a Performance Shortfall for such Performance Assessment Interval. ~~For any resource that is partially committed as a Capacity Performance Resource and partially committed as a Base Capacity Resource, the performance of such resource during a Performance Assessment Interval shall first be attributed to the resource's Capacity Performance Resource obligation; any performance by such resource in excess of the Capacity Performance Resource's Expected Performance shall be attributed to the resource's Base Capacity Resource obligation.~~

(d) Notwithstanding subsection (c) above, through the 2024/2025 Delivery Year, a Capacity Resource or Locational UCAP of a Capacity Market Seller or Locational UCAP Seller shall not be considered in the calculation of a Performance Shortfall for a Performance Assessment Interval to the extent such Capacity Resource or Locational UCAP was unavailable during such Performance Assessment Interval solely because the resource on which such Capacity Resource or Locational UCAP is based was on a Generator Planned Outage or Generator Maintenance Outage approved by the Office of the Interconnection, or was not scheduled to operate by the Office of the Interconnection, or was online but was scheduled down, by the Office of the Interconnection, based on a determination by the Office of the Interconnection that such scheduling action was appropriate to the security-constrained economic dispatch of the PJM Region. Such a resource shall be considered in the calculation of a Performance Shortfall if it otherwise was needed and would have been scheduled by the Office of the Interconnection to perform, but was not scheduled to operate, or was scheduled down, solely due to: (i) any operating parameter limitations submitted in the resource's offer, or (ii) the seller's submission of a market-based offer higher than its cost-based. In addition, notwithstanding subsection (c) above, a Price Responsive Demand registration shall not be considered in the calculation of a Performance Shortfall or Bonus Performance for a Performance Assessment Interval when the PRD Curve associated with such registration in the PJM Real-time Energy Market indicates a price point where no demand reduction is expected at the real-time LMP recorded during the Performance Assessment Interval.

(d-1). Notwithstanding subsection (c) above, effective with the 2025/2026 Delivery Year and subsequent Delivery Years, a Capacity Resource or Locational UCAP of a Capacity Market Seller or Locational UCAP Seller shall not be considered in the calculation of a Performance Shortfall for a Performance Assessment Interval to the extent such Capacity Resource or Locational UCAP was unavailable during such Performance Assessment Interval solely because the resource on which such Capacity Resource or Locational UCAP is based was on a Generator Planned Outage or Generator Maintenance Outage approved by the Office of the Interconnection. Further, the megawatts of a Capacity Resource that was scheduled to operate at a level below its expected performance shall also be excluded from the calculation of a Performance Shortfall for a Performance Assessment Interval to the extent such scheduling was not solely due to any operating parameter limitations submitted in the resource's schedule on which it was dispatched.

Notwithstanding the foregoing, except for a Capacity Resource that is on a Generator Planned Outage or Generator Maintenance Outage approved by the Office of the Interconnection, a Capacity Resource that is offline during a Performance Assessment Interval shall be included in the calculation of a Performance Shortfall unless the Office of the Interconnection affirmatively denies a request to come online for such resource. In addition, notwithstanding subsection (c) above, a Price Responsive Demand registration shall not be considered in the calculation of a Performance Shortfall for a Performance Assessment Interval when the PRD Curve associated with such registration in the PJM Real-time Energy Market indicates a price point where no demand reduction is expected at the real-time LMP recorded during the Performance Assessment Interval.

(e) Subject to the Non-Performance Charge Limit specified in subsection (f) hereof, each Capacity Market Seller and Locational UCAP Seller shall be assessed a Non-Performance Charge, which are auction clearing revenue adjustments and do not constitute a penalty rate or penalty provision, for each of its Capacity Resources or Locational UCAP that has a Performance Shortfall for a Performance Assessment Interval based on the following formula, applied to each such resource:

Non-Performance Charge = Performance Shortfall * Non-Performance Charge Rate

Where

For Capacity Performance Resources, Price Responsive Demand, and Seasonal Capacity Performance Resources, the Non-Performance Charge Rate = (Net Cost of New Entry (stated in terms of installed capacity) for the LDA and Delivery Year for which such calculation is performed * (the number of days in the Delivery Year / 30) / (the number of Real-Time Settlement Intervals in an hour).

~~and for Base Capacity Resources the Non-Performance Charge Rate = (Weighted Average Resource Clearing Price applicable to the resource * (the number of days in the Delivery Year / 30) (the number of Real-Time Settlement Intervals in an hour)~~

(f) Through the 2024/2025 Delivery Year, ~~T~~the Non-Performance Charges for each Capacity Performance Resource (including Locational UCAP from such a resource) and each PRD Provider for a Delivery Year shall not exceed a Non-Performance Charge Limit equal to 1.5 times the Net Cost of New Entry times the megawatts of Unforced Capacity committed by such resource or such PRD Provider times the number of days in the Delivery Year. All references to Net Cost of New Entry in this section 10A shall be to the Net Cost of New Entry for the LDA and Delivery Year for which the calculation is performed. ~~The total Non-Performance Charges for each Base Capacity Resource (including Locational UCAP from such a resource) for a Delivery Year shall not exceed a Non-Performance Charge Limit equal to the total payments due such Capacity Resource or Locational UCAP under Tariff, Attachment DD, section 5.14 for such Delivery Year.~~ The Non-Performance Charges for each Seasonal Capacity Performance Resource for a Delivery Year shall not exceed a Non-Performance Charge Limit equal to 1.5 times the Net Cost of New Entry times the megawatts of Unforced Capacity committed by such resource times the number of days in the season applicable to such resource.

(g) Revenues collected from assessment of Non-Performance Charges for a Performance Assessment Interval shall be distributed to each Market Participant, whether or not such Market Participant committed a Capacity Resource or Locational UCAP for a Performance Assessment Interval provided that energy or load reductions above the levels expected for such resource during such interval prior to 2025/2026 Delivery Year. Beginning with the 2025/2026 Delivery Year and subsequent Delivery Years, revenues collected from assessment of Non-Performance Charges for a Performance Assessment Interval shall be distributed to Market Participants of committed Generation Capacity Resources or Locational UCAP for a Performance Assessment Interval~~, that provided energy or load reductions above the levels expected for such resource during such interval~~. For purposes of this provision, the performance expected of a resource, and the revenue distribution payment, if any, for a resource, shall be determined in accordance with the following formulae:

Formula 1: Market Participant Bonus Performance = Actual Performance – Expected Performance

and

Formula 2: Performance Payment = (Market Participant Bonus Performance / All Market Participants Bonus Performance) * Non-Performance Charge Revenues.

Where the result of Formula 1 is a positive number and where:

> Actual Performance is as defined in subsection (c), provided, however, that Actual Performance for purposes of this calculation shall not exceed the megawatt level at which such resource was scheduled by the Office of the Interconnection during the Performance Assessment Intervals; and provided further that Actual Performance for a Market Participant that imports energy into the PJM Region during such Performance Assessment Interval shall be the net import, if any, from all interchange transactions scheduled by such Market Participant during such Performance Assessment Interval;
>
> Expected Performance is as defined in subsection (c), provided, however, that for purposes of this calculation, Expected Performance shall be zero for any resource that is not a Capacity Resource or Locational UCAP, or that is a Capacity Resource or Locational UCAP, but for which the Performance Assessment Interval occurs outside the resource's capacity obligation period~~, including, without limitation, a Base Capacity Demand Resource providing demand response during non-summer months~~; and
>
> All Market Participants Bonus Performance is the sum of the results of calculating Formula 1 of this subsection (g) for all Market Participants that have Bonus Performance during such Performance Assessment Interval.

~~(h) The provisions of this section 10A shall apply during the 2016/2017 Delivery Year, provided that:~~

~~(i) Non-Performance Charges shall be determined solely for and assessed solely on, Capacity Performance Resources committed for such Delivery Year;~~

~~(ii) The Non-Performance Charge shall be 0.5 times the Non-Performance Charge calculated under subsection (e) hereof; and~~

~~(iii) The Non-Performance Charge Limit for a Delivery Year shall be 0.75 times Net Cost of New Entry times the megawatts of Unforced Capacity committed by such resource times 365.~~

~~(i) The provisions of this section 10A shall apply during the 2017/2018 Delivery Year, provided that:~~

~~(i) Non-Performance Charges shall be determined solely for, and assessed solely on, Capacity Performance Resources committed for such Delivery Year;~~

~~(ii) The Non-Performance Charge shall be 0.6 times the Non-Performance Charge calculated under subsection (e) hereof; and~~

~~(iii) The Non-Performance Charge Limit for a Delivery Year shall be 0.9 times Net Cost of New Entry times the megawatts of Unforced Capacity committed by such resource times 365.~~

(h~~j~~) The Office of the Interconnection shall bill charges and credits for performance during Performance Assessment Intervals within three calendar months after the calendar month that included such Performance Assessment Intervals, provided, for any Non-Performance Charge, the amount shall be divided by the number of months remaining in the Delivery Year for which no invoice has been issued, and the resulting amount shall be invoiced each such remaining month in the Delivery Year. Notwithstanding, if there are less than six months remaining in the current Delivery Year for which no invoice has been issued, the Office of the Interconnection may, with prior notice to PJM Members, allocate in equal amounts any Non-Performance Charge in the remaining monthly bills for the current Delivery Year plus up to six monthly bills into the following Delivery Year for all Capacity Market Sellers that incur such a Non-Performance Charge (but in no event shall the total Non-Performance Charge be divided in more than nine monthly bills). Provided, for any Non-Performance Charges associated with Performance Assessment Intervals from December 23, 2022 and December 24, 2022, a Capacity Market Seller may elect, by providing notice to the Office of Interconnection by March 17, 2023, to divide the total amount of Non-Performance Charges by either (i) the number of remaining monthly bills in the current Delivery Year (i.e., 3 bills) or (ii) the number of remaining monthly bills in the current Delivery Year plus six additional monthly bills into the following Delivery Year (i.e., 9 bills); provided further, however, that for an election under subsection (ii) above, the monthly Non-Performance Charge shall be levelized to include interest for the six month period following the current Delivery Year, such interest amount being determined at the electric interest rate established by the Federal Energy Regulatory Commission at the time of such election. All interest collected in accordance with this provision shall be allocated to the total pool of bonus performance payments and distributed in accordance with Tariff, Attachment DD, section 10A(g).

Sections of the
PJM Reliability Assurance Agreement

(Marked / Redline Format)

C. Election, and Termination of Election, of FRR Alternative

1. No less than four months before the conduct of the Base Residual Auction for the first Delivery Year for which such election is to be effective, any Party seeking to elect the FRR Alternative shall notify the Office of the Interconnection in writing of such election. Such election shall be for a minimum term of five consecutive Delivery Years. No later than one month before such Base Residual Auction, such Party shall submit its FRR Capacity Plan demonstrating its commitment of Capacity Resources for the term of such election sufficient to meet such Party's Daily Unforced Capacity Obligation (and all other applicable obligations under this Schedule) for the load identified in such plan. Through the 2024/2025 Delivery Year, ~~N~~no later than the last business day prior to the start of the relevant Delivery Year in which Capacity Performance requirements shall apply to such FRR Entity, the FRR Entity must also elect whether it seeks to be subject to the Non-Performance Charge for Capacity Performance Resources~~,~~ and Seasonal Capacity Performance Resources~~, and Base Capacity Resources~~, as provided in Tariff, ~~section 10A of~~ Attachment DD, section 10A~~ of the PJM Tariff~~, and described in section G.1 of this Schedule 8.1, or to physical non-performance assessments, as described in section G.2 of this Schedule 8.1. Beginning with the 2025/2026 Delivery Year, the FRR Entity shall be subject to the Non-Performance Charge in accordance with Tariff, Attachment DD, section 10A, and described in RAA, Schedule 8.1.G.

2. An FRR Entity may terminate its election of the FRR Alternative effective with the commencement of any Delivery Year following the minimum five Delivery Year commitment by providing written notice of such termination to the Office of the Interconnection no later than two months prior to the Base Residual Auction for such Delivery Year. An FRR Entity that has terminated its election of the FRR Alternative shall not be eligible to re-elect the FRR Alternative for a period of five consecutive Delivery Years following the effective date of such termination.

3. Notwithstanding subsections C.1 and C.2 of this Schedule, in the event of a State Regulatory Structural Change, a Party may elect, or terminate its election of, the FRR Alternative effective as to any Delivery Year by providing written notice of such election or termination to the Office of the Interconnection in good faith as soon as the Party becomes aware of such State Regulatory Structural Change but in any event no later than two months prior to the Base Residual Auction for such Delivery Year.

4. To facilitate the elections and notices required by this Schedule, except a new FRR Entity's initial election, the Office of the Interconnection shall post, in addition to the information required by Section 5.11(a) of Attachment DD to the PJM Tariff, the percentage of Capacity Resources required to be located in each Locational Deliverability Area by no later than one month prior to the deadline for a Party to provide such elections and notices.

G. Capacity Resource Performance

1. Any Capacity Resource committed by an FRR Entity in an FRR Capacity Plan for a Delivery Year shall be subject during such Delivery Year to the charges set forth in Tariff, Attachment DD, section 7, Tariff, Attachment DD, section 9, Tariff, Attachment DD, section 10, Tariff, Attachment DD, section 10A, Tariff Attachment DD, section 11, Tariff, Attachment DD, section 11A, and Tariff, Attachment DD, section 13; provided, however: (i) the Daily Deficiency Rate under Tariff, Attachment DD, section 7, Tariff, Attachment DD, section 9, Tariff, Attachment DD, section 11A, and Tariff, Attachment DD, section 13 shall be 1.20 times the Capacity Resource Clearing Price resulting from all RPM Auctions for such Delivery Year for the LDA encompassing the Zone of the FRR Entity, weight-averaged for the Delivery Year based on the prices established and quantities cleared in such auctions); (ii) the charges set forth in Tariff, Attachment DD, section 10A shall apply only for the 2019/2020 and subsequent Delivery Years and only to those FRR Entities which opted to be subject to the Non-Performance Charge under section C.1 of this Schedule 8.1 and the charge rates under section 10A thereof for Base Capacity Resources shall be the Capacity Resource Clearing Price resulting from the RPM Auctions for the Delivery Year for the LDA encompassing the Zone of the FRR Entity, weight-averaged as described above; and (iii) the charge rates under Tariff, Attachment DD, section 10 and Tariff, Attachment DD, section 11, shall be the Capacity Resource Clearing Price resulting from the RPM Auctions for the Delivery Year for the LDA encompassing the Zone of the FRR Entity, weight-averaged as described above. An FRR Entity shall have the same opportunities to cure deficiencies and avoid or reduce associated charges during the Delivery Year that a Market Seller has under Tariff, Attachment DD, section 7, Tariff, Attachment DD, section 9, Tariff, Attachment DD, section 10, Tariff, Attachment DD, section 10A, Tariff, Attachment DD, section 11, and Tariff, Attachment DD, section 11A. An FRR Entity may cure deficiencies and avoid or reduce associated charges prior to the Delivery Year by procuring replacement Unforced Capacity outside of any RPM Auction and committing such capacity in its FRR Capacity Plan.

2. Through the 2024/2025 Delivery Year, ~~F~~for any FRR Entity which opted to be subject to physical non-performance assessments under RAA, Schedule 8.1, section C.1, such FRR Entity will not be subject to charges under Tariff, Attachment DD, section 10A, but, rather, it will be required to update its FRR Capacity Plan with additional megawatts of Capacity Performance Resources or Seasonal Capacity Performance Resources determined in accordance with the following: For each Performance Assessment Interval, the Actual Performance and Expected Performance of each resource contained in an FRR Entity's FRR Capacity Plan or Price Responsive Demand committed to reduce the FRR Entity's unforced capacity obligation ~~(for the 2022/2023 Delivery Year and subsequent Delivery Years)~~ will be determined in the same fashion as prescribed by the Tariff, Attachment DD, section 10A. ~~, and for such hour, a net Performance Shortfall shall be determined separately for Capacity Performance Resources and for Base Capacity Resources. If, for a Performance Assessment Interval, the combined Actual Performance of all an FRR Entity's committed Capacity Performance Resources or Price Responsive Demand committed by the FRR Entity (for the 2022/2023 Delivery Year and subsequent Delivery Years) exceeds the Expected Performance of such resources or Price Responsive Demand, then such over-performance may be applied to any Performance Shortfall experienced by such FRR Entity's Base Capacity Resources for such hour. If, for a Performance Assessment Interval, the combined Actual Performance of all an FRR Entity's committed Base Capacity Resources exceeds the Expected Performance of such resources, then such over-performance may be applied to any Performance~~

~~Shortfall experienced by such FRR Entity's Capacity Performance Resources or Price Responsive Demand committed by the FRR Entity (for the 2022/2023 Delivery Year and subsequent Delivery Years) for such hour. For the 2020/2021 Delivery Year, t~~The net Performance Shortfall determined for Capacity Performance Resources and Price Responsive Demand shall include the performance of Seasonal Capacity Performance Resources contained in the FRR Capacity Plan.

The FRR Entity's net Performance Shortfall among Capacity Performance Resources or Price Responsive Demand, if any, for each such Performance Assessment Interval shall be multiplied by a rate of 0.00139 MWs/Performance Assessment Interval to establish the additional MW quantities of Capacity Performance Resources, Seasonal Capacity Performance Resources, or Price Responsive Demand that such FRR Entity must add to its FRR Capacity Plan for the next Delivery Year. Notwithstanding the foregoing, the total additional MWs required as a result of non-performance by the FRR Entity's Capacity Performance Resources in any Delivery Year shall not exceed a MW quantity equal to 0.5 times the MW quantity of the Capacity Performance Resources and Seasonal Capacity Performance Resources that were committed in the FRR Capacity Plan for such Delivery Year and Price Responsive Demand committed such Delivery Year. ~~(for the 2022/2023 Delivery Year and subsequent Delivery Years). The FRR Entity's net Performance Shortfall among Base Capacity Resources, if any, for each such Performance Assessment Interval shall be multiplied by a rate of [(0.00139 MWs/Performance Assessment Interval) times (the Base Capacity Resource Clearing Price resulting from the RPM Auctions for the Delivery Year for the LDA encompassing the Zone of the FRR Entity, weight-averaged for the Delivery Year based on the prices established and quantities cleared in such auctions, divided by the Net CONE established for such LDA for the Delivery Year)] to establish the additional MW quantities of Capacity Performance Resources or Seasonal Capacity Performance Resources that such FRR Entity must add to its FRR Capacity Plan for the next Delivery Year. Notwithstanding the foregoing, the total additional MWs required as a result of non-performance by the FRR Entity's Base Capacity Resources in any Delivery Year shall not exceed a MW quantity equal to [(0.5 times the MW quantity of the Base Capacity Resources that were committed in the FRR Capacity Plan for such Delivery Year) times (the Base Capacity Resource Clearing Price resulting from the RPM Auctions for the Delivery Year for the LDA encompassing the Zone of the FRR Entity, weight-averaged for the Delivery Year based on the prices established and quantities cleared in such auctions, divided by the Net CONE established for such LDA for the Delivery Year)].~~

An FRR Entity that elects the physical option shall not be eligible for, or subject to, the revenue allocation described in Tariff, Attachment DD, section 10A(g).

Attachment B

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)

ATTACHMENT M – APPENDIX

I. CONFIDENTIALITY OF DATA AND INFORMATION

A. Party Access:

1. No Member shall have a right hereunder to receive or review any documents, data or other information of another Member, including documents, data or other information provided to the Market Monitoring Unit, to the extent such documents, data or information have been designated as confidential pursuant to the procedures adopted by the Market Monitoring Unit or to the extent that they have been designated as confidential by such other Member; provided, however, a Member may receive and review any composite documents, data and other information that may be developed based on such confidential documents, data or information if the composite does not disclose any individual Member's confidential data or information.

2. Except as may be provided in this Appendix, the Plan, the PJM Operating Agreement or in the PJM Tariff, the Market Monitoring Unit shall not disclose to PJM Members or to third parties, any documents, data, or other information of a Member or entity applying for Membership, to the extent such documents, data, or other information has been designated confidential pursuant to the procedures adopted by the Market Monitoring Unit or by such Member or entity applying for membership; provided that nothing contained herein shall prohibit the Market Monitoring Unit from providing any such confidential information to its agents, representatives, or contractors to the extent that such person or entity is bound by an obligation to maintain such confidentiality.

The Market Monitoring Unit, its designated agents, representatives, and contractors shall maintain as confidential the electronic tag ("e-Tag") data of an e-Tag Author or Balancing Authority (defined as those terms are used in FERC Order No. 771) to the same extent as Member data under this section I. Nothing contained herein shall prohibit the Market Monitoring Unit from sharing with the market monitor of another Regional Transmission Organization ("RTO"), Independent System Operator ("ISO"), upon their request, the e-Tags of an e-Tag Author or Balancing Authority for intra-PJM Region transactions and interchange transactions scheduled to flow into, out of or through the PJM Region, to the extent such market monitor has requested such information as part of its investigation of possible market violations or market design flaws, and to the extent that such market monitor is bound by a tariff provision requiring that the e-Tag data be maintained as confidential, or in the absence of a tariff requirement governing confidentiality, a written agreement with the Market Monitoring Unit consistent with FERC Order No. 771, and any clarifying orders and implementing regulations.

The Market Monitoring Unit shall collect and use confidential information only in connection with its authority under this Appendix, the Plan, the PJM Operating Agreement or in the PJM Tariff and the retention of such information shall be in accordance with the Office of the Interconnection's data retention policies.

3. Nothing contained herein shall prevent the Market Monitoring Unit from releasing a Member's confidential data or information to a third party provided that the Member has

delivered to the Market Monitoring Unit specific, written authorization for such release setting forth the data or information to be released, to whom such release is authorized, and the period of time for which such release shall be authorized. The Market Monitoring Unit shall limit the release of a Member's confidential data or information to that specific authorization received from the Member. Nothing herein shall prohibit a Member from withdrawing such authorization upon written notice to the Market Monitoring Unit, who shall cease such release as soon as practicable after receipt of such withdrawal notice.

4. Reciprocal provisions to this section I hereof, delineating the confidentiality requirements of the Office of the Interconnection and PJM members, are set forth in Operating Agreement, section 18.17.

B. <u>Required Disclosure</u>:

1. Notwithstanding anything in the foregoing section to the contrary, and subject to the provisions of section I.C below, if the Market Monitoring Unit is required by applicable law, order, or in the course of administrative or judicial proceedings, to disclose to third parties, information that is otherwise required to be maintained in confidence pursuant to the PJM Tariff, PJM Operating Agreement, Tariff, Attachment M or this Appendix, the Market Monitoring Unit may make disclosure of such information; provided, however, that as soon as the Market Monitoring Unit learns of the disclosure requirement and prior to making disclosure, the Market Monitoring Unit shall notify the affected Member or Members of the requirement and the terms thereof and the affected Member or Members may direct, at their sole discretion and cost, any challenge to or defense against the disclosure requirement. The Market Monitoring Unit shall cooperate with such affected Members to the maximum extent practicable to minimize the disclosure of the information consistent with applicable law. The Market Monitoring Unit shall cooperate with the affected Members to obtain proprietary or confidential treatment of such information by the person to whom such information is disclosed prior to any such disclosure.

2. Nothing in this section I shall prohibit or otherwise limit the Market Monitoring Unit's use of information covered herein if such information was: (i) previously known to the Market Monitoring Unit without an obligation of confidentiality; (ii) independently developed by or for the Office of the Interconnection and/or the Market Monitoring Unit using non-confidential information; (iii) acquired by the Office of the Interconnection and/or the Market Monitoring Unit from a third party which is not, to the Office of the Interconnection's or Market Monitoring Unit's knowledge, under an obligation of confidence with respect to such information; (iv) which is or becomes publicly available other than through a manner inconsistent with this section I.

3. The Market Monitoring Unit shall impose on any contractors retained to provide technical support or otherwise to assist with the implementation of the Plan or this Appendix a contractual duty of confidentiality consistent with the Plan or this Appendix. A Member shall not be obligated to provide confidential or proprietary information to any contractor that does not assume such a duty of confidentiality, and the Market Monitoring Unit shall not provide any such information to any such contractor without the express written permission of the Member providing the information.

C. <u>Disclosure to FERC and CFTC</u>:

1. Notwithstanding anything in this section I to the contrary, if the FERC, the Commodity Futures Trading Commission ("CFTC") or the staff of those commissions, during the course of an investigation or otherwise, requests information from the Market Monitoring Unit that is otherwise required to be maintained in confidence pursuant to the PJM Tariff, the PJM Operating Agreement, the Plan or this Appendix, the Market Monitoring Unit shall provide the requested information to the FERC, CFTC or their staff, within the time provided for in the request for information. In providing the information to the FERC or its staff, the Market Monitoring Unit may request, consistent with 18 C.F.R. §§ 1b.20 and 388.112, or to the CFTC or its staff, the Market Monitoring Unit may request, consistent with 17 C.F.R. §§ 11.3 and 145.9, that the information be treated as confidential and non-public by the respective commission and its staff and that the information be withheld from public disclosure. The Market Monitoring Unit shall promptly notify any affected Member(s) if the Market Monitoring Unit receives from the FERC, CFTC or their staff, written notice that the commission has decided to release publicly or has asked for comment on whether such commission should release publicly, confidential information previously provided to a commission Market Monitoring Unit.

2. The foregoing section I.C.1 shall not apply to requests for production of information under Subpart D of the FERC's Rules of Practice and Procedure (18 CFR Part 385) in proceedings before FERC and its administrative law judges. In all such proceedings, the Office of the Interconnection and/or the Market Monitoring Unit shall follow the procedures in section I.B.

D. <u>Disclosure to Authorized Commissions</u>:

1. Notwithstanding anything in this section I to the contrary, the Market Monitoring Unit shall disclose confidential information, otherwise required to be maintained in confidence pursuant to the PJM Tariff, the PJM Operating Agreement, the Plan or this Appendix, to an Authorized Commission under the following conditions:

(i) The Authorized Commission has provided the FERC with a properly executed Certification in the form attached to the PJM Operating Agreement as Operating Agreement, Schedule 10A. Upon receipt of the Authorized Commission's Certification, the FERC shall provide public notice of the Authorized Commission's filing pursuant to 18 C.F.R. § 385.2009. If any interested party disputes the accuracy and adequacy of the representations contained in the Authorized Commission's Certification, that party may file a protest with the FERC within 14 days of the date of such notice, pursuant to 18 C.F.R. § 385.211. The Authorized Commission may file a response to any such protest within seven days. Each party shall bear its own costs in connection with such a protest proceeding. If there are material changes in law that affect the accuracy and adequacy of the representations in the Certification filed with the FERC, the Authorized Commission shall, within thirty (30) days, submit an amended Certification identifying such changes. Any such amended Certification shall be subject to the same procedures for comment and review by the FERC as set forth above in this paragraph.

(ii) Neither the Office of the Interconnection nor the Market Monitoring Unit may disclose data to an Authorized Commission during the FERC's consideration of the Certification and any filed protests. If the FERC does not act upon an Authorized Commission's Certification within 90 days of the date of filing, the Certification shall be deemed approved and the Authorized Commission shall be permitted to receive confidential information pursuant to this Section I. In the event that an interested party protests the Authorized Commission's Certification and the FERC approves the Certification, that party may not challenge any Information Request made by the Authorized Commission on the grounds that the Authorized Commission is unable to protect the confidentiality of the information requested, in the absence of a showing of changed circumstances.

(iii) Any confidential information provided to an Authorized Commission pursuant to this section I shall not be further disclosed by the recipient Authorized Commission except by order of the FERC.

(iv) The Market Monitoring Unit shall be expressly entitled to rely upon such Authorized Commission Certifications in providing confidential information to the Authorized Commission, and shall in no event be liable, or subject to damages or claims of any kind or nature hereunder, due to the ineffectiveness or inaccuracy of such Authorized Commission Certifications.

(v) The Authorized Commission may provide confidential information obtained from the Market Monitoring Unit to such of its employees, attorneys and contractors as needed to examine or handle that information in the course and scope of their work on behalf of the Authorized Commission, provided that (a) the Authorized Commission has internal procedures in place, pursuant to the Certification, to ensure that each person receiving such information agrees to protect the confidentiality of such information (such employees, attorneys or contractors to be defined hereinafter as "Authorized Persons"); (b) the Authorized Commission provides, pursuant to the Certification, a list of such Authorized Persons to the Office of the Interconnection and the Market Monitoring Unit and updates such list, as necessary, every ninety (90) days; and (c) any third-party contractors provided access to confidential information sign a nondisclosure agreement in the form attached to the PJM Operating Agreement as Operating Agreement, Schedule 10 before being provided access to any such confidential information.

2. The Market Monitoring Unit may, in the course of discussions with an Authorized Person, orally disclose information otherwise required to be maintained in confidence, without the need for a prior Information Request. Such oral disclosures shall provide enough information to enable the Authorized Person or the Authorized Commission with which that Authorized Person is associated to determine whether additional Information Requests are appropriate. The Market Monitoring Unit will not make any written or electronic disclosures of confidential information to the Authorized Person pursuant to this section I.D.2. In any such discussions, the Market Monitoring Unit shall ensure that the individual or individuals receiving such confidential information are Authorized Persons as defined herein, orally designate confidential information that is disclosed, and refrain from identifying any specific Affected Member whose information is disclosed. The Market Monitoring Unit shall also be authorized to assist Authorized Persons in interpreting confidential information that is disclosed. The Market

Monitoring Unit shall provide any Affected Member with oral notice of any oral disclosure immediately, but not later than one (1) Business Day after the oral disclosure. Such oral notice to the Affected Member shall include the substance of the oral disclosure, but shall not reveal any confidential information of any other Member and must be received by the Affected Member before the name of the Affected Member is released to the Authorized Person; provided however, disclosure of the identity of the Affected Party must be made to the Authorized Commission with which the Authorized Person is associated within two (2) Business Days of the initial oral disclosure.

3. As regards Information Requests:

(i) Information Requests to the Office of the Interconnection and/or Market Monitoring Unit by an Authorized Commission shall be in writing, which shall include electronic communications, addressed to the Market Monitoring Unit, and shall: (a) describe the information sought in sufficient detail to allow a response to the Information Request; (b) provide a general description of the purpose of the Information Request; (c) state the time period for which confidential information is requested; and (d) re-affirm that only Authorized Persons shall have access to the confidential information requested. The Market Monitoring Unit shall provide an Affected Member with written notice, which shall include electronic communication, of an Information Request by an Authorized Commission as soon as possible, but not later than two (2) Business Days after the receipt of the Information Request.

(ii) Subject to the provisions of section I.D.3(iii) below, the Market Monitoring Unit shall supply confidential information to the Authorized Commission in response to any Information Request within five (5) Business Days of the receipt of the Information Request, to the extent that the requested confidential information can be made available within such period; provided however, that in no event shall confidential information be released prior to the end of the fourth (4th) Business Day without the express consent of the Affected Member. To the extent that the Market Monitoring Unit cannot reasonably prepare and deliver the requested confidential information within such five (5) day period, it shall, within such period, provide the Authorized Commission with a written schedule for the provision of such remaining confidential information. Upon providing confidential information to the Authorized Commission, the Market Monitoring Unit shall either provide a copy of the confidential information to the Affected Member(s), or provide a listing of the confidential information disclosed; provided, however, that the Market Monitoring Unit shall not reveal any Member’s confidential information to any other Member.

(iii) Notwithstanding section I.D.3(ii), above, should the Office of the Interconnection, the Market Monitoring Unit or an Affected Member object to an Information Request or any portion thereof, any of them may, within four (4) Business Days following the Market Monitoring Unit’s receipt of the Information Request, request, in writing, a conference with the Authorized Commission to resolve differences concerning the scope or timing of the Information Request; provided, however, nothing herein shall require the Authorized Commission to participate in any conference. Any party to the conference may seek assistance from FERC staff in resolution of the dispute or terminate the conference process at any time. Should such conference be refused or terminated by any participant or should such conference not resolve the dispute, then the Office of the Interconnection, Market Monitoring Unit, or the Affected Member may file a complaint with the FERC pursuant to Rule 206 objecting to the Information Request within ten (10) Business Days following receipt of written notice from any conference participant terminating such conference. Any complaints filed at the FERC objecting to a particular Information Request shall be designated by the party as a "fast track" complaint and each party shall bear its own costs in connection with such FERC proceeding. The grounds for such a complaint shall be limited to the following: (a) the Authorized Commission is no longer able to preserve the confidentiality of the requested information due to changed circumstances relating to the Authorized Commission's ability to protect confidential information arising since the filing of or rejection of a protest directed to the Authorized Commission's Certification; (b) complying with the Information Request would be unduly burdensome to the complainant, and the complainant has made a good faith effort to negotiate limitations in the scope of the requested information; or (c) other exceptional circumstances exist such that complying with the Information Request would result in harm to the complainant. There shall be a presumption that "exceptional circumstances," as used in the prior sentence, does not include circumstances in which an Authorized Commission has requested wholesale market data (or Market Monitoring Unit workpapers that support or explain conclusions or analyses) generated in the ordinary course and scope of the operations of the Market Monitoring Unit. There shall be a presumption that circumstances in which an Authorized Commission has requested personnel files, internal emails and internal company memos, analyses and related work product constitute "exceptional circumstances" as used in the prior sentence. If no complaint challenging the Information Request is filed within the ten (10) day period defined above, the Office of the Interconnection and/or Market Monitoring Unit shall utilize its best efforts to respond to the Information Request promptly. If a complaint is filed, and the Commission does not act on that complaint within ninety (90) days, the complaint shall be deemed denied and the Market Monitoring Unit shall use its best efforts to respond to the Information Request promptly.

(iv) Any Authorized Commission may initiate appropriate legal action at the FERC within ten (10) Business Days following receipt of information designated as "Confidential," challenging such designation. Any complaints filed at FERC objecting to the designation of information as "Confidential" shall be designated by the party as a "fast track" complaint and each party shall bear its own costs in connection with such FERC proceeding. The party filing such a complaint shall be required to prove that the material disclosed does not merit "Confidential" status because it is publicly available from other sources or contains no trade secret or other sensitive commercial information (with "publicly available" not being deemed to include unauthorized disclosures of otherwise confidential data).

4. In the event of any breach of confidentiality of information disclosed pursuant to an Information Request by an Authorized Commission or Authorized Person:

(i) The Authorized Commission or Authorized Person shall promptly notify the Market Monitoring Unit, who shall, in turn, promptly notify any Affected Member of any inadvertent or intentional release, or possible release, of confidential information provided pursuant to this section I.

(ii) The Office Market Monitoring Unit shall terminate the right of such Authorized Commission to receive confidential information under this section I upon written notice to such Authorized Commission unless: (i) there was no harm or damage suffered by the Affected Member; or (ii) similar good cause is shown. Any appeal of the Market Monitoring Unit's actions under this section I shall be to Commission. An Authorized Commission shall be entitled to reestablish its certification as set forth in section I.D.1 by submitting a filing with the Commission showing that it has taken appropriate corrective action. If the Commission does not act upon an Authorized Commission's recertification filing with sixty (60) days of the date of the filing, the recertification shall be deemed approved and the Authorized Commission shall be permitted to receive confidential information pursuant to this section.

(iii) The Office of the Interconnection, the Market Monitoring Unit, and/or the Affected Member shall have the right to seek and obtain at least the following types of relief: (a) an order from the FERC requiring any breach to cease and preventing any future breaches; (b) temporary, preliminary, and/or permanent injunctive relief with respect to any breach; and (c) the immediate return of all confidential information to the Market Monitoring Unit.

(iv) No Authorized Person or Authorized Commission shall have responsibility or liability whatsoever under this section for any and all liabilities, losses, damages, demands, fines, monetary judgments, penalties, costs and expenses caused by, resulting from, or arising out of or in connection with the release of confidential information to persons not authorized to receive it, provided that such Authorized Person is an agent, servant, employee or member of an Authorized Commission at the time of such unauthorized release. Nothing in this section I.D.4(iv) is intended to limit the liability of any person who is not an agent, servant, employee or member of an Authorized Commission at the time of such unauthorized release for any and all economic losses, damages, demands, fines, monetary judgments, penalties, costs and expenses caused by, resulting from, or arising out of or in connection with such unauthorized release.

(v) Any dispute or conflict requesting the relief in section I.D.4(ii) or I.D.4(iii)(a) above, shall be submitted to the FERC for hearing and resolution. Any dispute or conflict requesting the relief in section I.D.4(iii)(c) above may be submitted to FERC or any court of competent jurisdiction for hearing and resolution.

E. [Reserved]

II. <u>DEVELOPMENT OF INPUTS FOR PROSPECTIVE MITIGATION</u>

A. <u>Offer Price Caps</u>:

1. The Market Monitor or his designee shall advise the Office of the Interconnection whether it believes that the cost references, methods and rules included in the Cost Development Guidelines are accurate and appropriate, as specified in the PJM Manuals.

2. The Market Monitoring Unit shall review the incremental costs (defined in Operating Agreement, Schedule 1, section 6.4.2and the parallel provisions of Tariff, Attachment K-Appendix, section 6.4.2) included in the Offer Price Cap of a generating unit in order to ensure

that the Market Seller has correctly applied the Cost Development Guidelines, including its PJM-approved Fuel Cost Policy, and that the level of the Offer Price Cap is otherwise acceptable. The Market Monitoring Unit shall inform PJM if it believes a Market Seller has submitted a cost-based offer that is not compliant with these criteria and whether it recommends that PJM assess the applicable penalty therefor, pursuant to Operating Agreement, Schedule 2.

3. On or before the 21st day of each month, the Market Monitoring Unit shall calculate in accordance with the applicable criteria whether each generating unit with an offer cap calculated under Operating Agreement, Schedule 1, section 6.4.2 and the parallel provisions of Tariff, Attachment K-Appendix, section 6.4.2 is eligible to include an adder based on Frequently Mitigated Unit or Associated Unit status, and shall issue a written notice of the applicable adder, with a copy to the Office of the Interconnection, to the Market Seller for each unit that meets the criteria for Frequently Mitigated Unit or Associated Unit status.

4. Notwithstanding the number of jointly pivotal suppliers in any hour, if the Market Monitoring Unit determines that a reasonable level of competition will not exist based on an evaluation of all facts and circumstances, it may propose to the Commission the removal of offer-capping suspensions otherwise authorized by Operating Agreement, Schedule 1, section 6.4 and the parallel provisions of Tariff, Attachment K-Appendix, section 6.4. Such proposals shall take effect upon Commission acceptance of the Market Monitoring Unit's filing.

5. The Market Monitoring Unit shall review all Fuel Cost Policies submitted by Market Sellers for market power concerns. The Market Monitoring Unit shall communicate its determination regarding these criteria to PJM and the Market Seller pursuant to the process further described in PJM Manual 15.

B. Minimum Generator Operating Parameters:

1. For the 2014/2015 through 2017/2018 Delivery Years, the Market Monitoring Unit shall provide to the Office of the Interconnection a table of default unit class specific parameter limits to be known as the "Parameter Limited Schedule Matrix" to be included in Operating Agreement, Schedule 1, section 6.6(c) and the parallel provisions of Tariff, Attachment K-Appendix, section 6.6(c). The Parameter Limited Schedule Matrix shall include default values on a unit-type basis as specified in Operating Agreement, Schedule 1, section 6.6(c) and the parallel provisions of Tariff, Attachment K-Appendix, section 6.6(c). The Market Monitoring Unit shall review the Parameter Limited Schedule Matrix annually, and, in the event it determines that revision is appropriate, shall provide a revised matrix to the Office of the Interconnection by no later than December 31 prior to the annual enrollment period.

2. The Market Monitoring Unit shall notify Market Sellers of generating units and the Office of the Interconnection no later than April 1 of its determination of market power concerns raised regarding each request for a period exception or persistent exception to a value specified in the Parameter Limited Schedule Matrix or the parameters defined in Operating Agreement, Schedule 1, section 6.6 and the parallel provisions of Tariff, Attachment K-Appendix, section 6.6 and the PJM Manuals, provided that the Market Monitoring Unit receives such request by no later than February 28.

If, prior to the scheduled termination date, a Market Seller submits a request to modify a temporary exception, the Market Monitoring Unit shall review such request using the same standard utilized to evaluate period exception and persistent exception requests, and shall provide its determination of whether the request raises market power concerns, and, if so, any modifications that would alleviate those concerns, to the Market Seller, with a copy to Office of the Interconnection, by no later than 15 Business Days from the date of the modification request.

3. When a Market Seller notifies the Market Monitoring Unit of a material change to the facts relied upon by the Market Monitoring Unit and/or the Office of the Interconnection to support a parameter limited schedule period or persistent exception, the Market Monitoring Unit shall make a determination, and provide written notification to the Office of the Interconnection and the Market Seller, of any change to its determination regarding the exemption request, based on the material change in facts, by no later than 15 Business Days after receipt of such notice.

4. The Market Monitoring Unit shall notify the Office of the Interconnection of any risk premium to which it and a Market Seller owning or operating nuclear generation resource agree or its determination if agreement is not obtained. If a Market Seller submits a risk premium for its nuclear generation resource that is inconsistent with its agreement or inconsistent with the Market Monitoring Unit's determination regarding such risk premium, the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns pursuant to Tariff, Attachment M.

C. <u>RPM Must-Offer Requirement</u>:

1. The Market Monitoring Unit shall maintain, post on its website and provide to the Office of the Interconnection prior to each RPM Auction (updated, as necessary, on at least a quarterly basis), a list of Existing Generation Capacity Resources located in the PJM Region that are subject to the RPM must-offer requirement set forth in Tariff, Attachment DD, section 6.6.

2. The Market Monitoring Unit shall evaluate requests submitted by Capacity Market Sellers for a determination that a Generation Capacity Resource, or any portion thereof, be removed from Capacity Resource status or exempted from status as a Generation Capacity Resource subject to section II.C.1 above and inform both the Capacity Market Seller and the Office of the Interconnection of such determination in writing by no later ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction. 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 Tariff, Attachment DD.

3. The Market Monitoring Unit shall evaluate the data and documentation provided to it by a potential Capacity Market Seller to establish the EFORd to be included in a Sell Offer applicable to each resource pursuant to Tariff, Attachment DD, section 6.6(b). If a Capacity Market Seller timely submits a request for an alternative maximum level of 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 Market Monitoring Unit shall attempt to reach agreement with the Capacity Market Seller on the alternate maximum level of the 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 ninety (90) days prior to the commencement of the offer period for the Base Residual Auction for the applicable Delivery Year, the Market Monitoring Unit shall notify the Office of the Interconnection in writing, notifying the Capacity Market Seller by copy of the same, of any alternative maximum EFORd to which it and the Capacity Market Seller agree or its determination of the alternative maximum EFORd if agreement is not obtained.

4. The Market Monitoring Unit shall consider the documentation provided to it by a potential Capacity Market Seller pursuant to Tariff, Attachment DD, section 6.6 of Attachment DD, and determine whether a resource owned or controlled by such Capacity Market Seller meets the criteria to qualify for an exception to the RPM must-offer requirement because the resource (i) is reasonably expected to be physically unable to participate in the relevant auction; (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. The Market Monitoring Unit shall notify the Capacity Market Seller and the Office of the Interconnection of its determination by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction.

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.

5. If a Capacity Market Seller submits for the portion of a Generation Capacity Resource that it owns or controls, and the Office of Interconnection accepts, a Sell Offer (i) at a level of installed capacity that the Market Monitoring Unit believes is inconsistent with the level established under Tariff, Attachment DD, section 5.6.6, (ii) at a level of installed capacity inconsistent with its determination of eligibility for an exception listed in section II.C.4 above, or (iii) a maximum EFORd that the Market Monitoring Unit believes is inconsistent with the maximum level determined under section II.C.3 of this Appendix, the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and/or request a determination from the Commission that would require the Generation Capacity Resource to submit a new or revised Sell Offer, notwithstanding any determination to the contrary made under Tariff, Attachment DD, section 6.6.

The Market Monitoring Unit shall also consider the documentation provided by the Capacity Market Seller pursuant to Tariff, Attachment DD, section 6.6, for generation resources for which the Office of the Interconnection has not approved an exception to the RPM must-offer requirement as set forth in Tariff, Attachment DD, section 6.6(g), to determine whether the Capacity Market Seller’s failure to offer part or all of one or more generation resources into an RPM Auction would result in an increase of greater than five percent in any Zonal Capacity Price determined through such auction as required by Tariff, Attachment DD, section 6.6(i), and shall inform both the Capacity Market Seller and the Office of the Interconnection of its determination by no later than two (2) Business Days after the close of the offer period for the applicable RPM Auction.

D. <u>Unit Specific Minimum Sell Offers:</u>

1. If a Capacity Market Seller timely submits an exception request, with all of the required documentation as specified in Tariff, Attachment DD, section*s* 5.14(h) *and 5.14(h-1)*, the Market Monitoring Unit shall review the request and documentation and shall provide in writing to the Capacity Market Seller and the Office of the Interconnection by no later than ninety (90) days prior the commencement of the offer period for the RPM Auction in which it seeks to submit its Sell Offer (a) its determination whether the level of the proposed Sell Offer raises market power concerns, and (b) if so it shall calculate and provide to such Capacity Market Seller a minimum Sell offer Based on the data and documentation received.

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

E. <u>Market Seller Offer Caps</u>:

1. Based on the data and calculations submitted by the Capacity Market Sellers for each Existing Generation Capacity Resource and the formulas specified in Tariff, Attachment DD,

section 6.7(d), the Market Monitoring Unit shall calculate the Market Seller Offer Cap for each such resource and provide it to the Capacity Market Seller and the Office of the Interconnection by no later than ninety (90) days before the commencement of the offer period for the applicable RPM Auction.

2. The Market Monitoring Unit must attempt to reach agreement with the Capacity Market Seller on the appropriate 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. If such agreement cannot be reached, then the Market Monitoring Unit shall inform the Capacity Market Seller and the Office of the Interconnection of its determination of the appropriate 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, and the Market Monitoring Unit may pursue any action available to it under Attachment M.

F. <u>Mitigation of Offers from Planned Generation Capacity Resources</u>:

Pursuant to Tariff, Attachment DD, section 6.5, the Market Monitoring Unit shall evaluate Sell Offers for Planned Generation Capacity Resources to determine whether market power mitigation should be applied and 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.

G. <u>Data Submission</u>:

Pursuant to Tariff, Attachment DD, section 6.7, the Market Monitoring Unit may request 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. All data submitted to the Office of the Interconnection or the Market Monitoring Unit by a Market Participant is subject to verification by the Market Monitoring Unit.

H. <u>Determination of Default Avoidable Cost Rates</u>:

1. The Market Monitoring Unit shall conduct an annual review of the table of default Avoidable Cost Rates included in Tariff, Attachment DD, section 6.7(c) and calculated on the bases set forth therein, and determine whether the values included therein need to be updated. If the Market Monitoring Unit determines that the Avoidable Cost Rates need to be updated, it shall provide to the Office of the Interconnection updated values or notice of its determination that updated values are not needed by no later than September 30th of each year.

2. The Market Monitoring Unit shall indicate in its posted reports on RPM performance the number of Generation Capacity Resources and megawatts per LDA that use the retirement default Avoidable Cost Rates.

3. If a Capacity Market Seller does not elect to use a default Avoidable Cost Rate and has timely provided to the Market Monitoring Unit its request to apply a unit-specific Avoidable Cost Rate, along with the data described in Tariff, Attachment DD, section 6.7, the Market Monitoring Unit shall calculate the Avoidable Cost Rate and provide a unit-specific value to the Capacity Market Seller for each such resource, and notify the Capacity Market Seller and the Office of the Interconnection in writing by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction whether it agrees that the unit-specific Avoidable Cost Rate is acceptable. The Capacity Market Seller and Office of the Interconnection's deadlines relating to the submittal and acceptance of a request for a unit-specific Avoidable Cost Rate are delineated in Tariff, Attachment DD, section 6.7(d).

I. <u>Determination of PJM Market Revenues</u>:

The Market Monitoring Unit shall calculate the Projected PJM Market Revenues for any Generation Capacity Resource to which the Avoidable Cost Rate is applied pursuant to Tariff, Attachment DD, section 6.8(d) and Tariff, Attachment DD, section 6.8(d-1), and notify the Capacity Market Seller and the Office of the Interconnection of its determination in writing by no later than one hundred fifty (150) days for the preliminary and no later than one hundred twenty-five (125) days for the final values prior to the commencement of the offer period for the applicable RPM Auction.

J. <u>Determination of Opportunity Costs</u>:

The Market Monitoring Unit shall review and verify the documentation of prices available to Existing Generation Capacity Resources in markets external to PJM and proposed for inclusion in Opportunity Costs pursuant to Tariff, Attachment DD, section 6.7(d)(ii). The Market Monitoring Unit shall notify, in writing, such Generation Capacity Resource and the Office of the Interconnection if it is dissatisfied with the documentation provided and whether it objects to the inclusion of such Opportunity Costs in a Market Seller Offer by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction. If such Generation Capacity Resource submits a Market Seller Offer that includes Opportunity Costs that have not been documented and verified to the Market Monitoring Unit's satisfaction, then the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and request a determination that would require the Generation Capacity Resource to remove them.

III. <u>BLACKSTART SERVICE</u>

A. Upon the submission by a Black Start Unit owner of a request for Black Start Service revenue requirements and changes to the Black Start Service revenue requirements for the Black Start Unit, the Black Start Unit owner and the Market Monitoring Unit shall attempt to agree to values on the level of each component included in the Black Start Service revenue requirements by no later than May 14 of each year. The Market Monitoring Unit shall calculate the revenue requirement for each Black Start Unit and provide its calculation to the Office of the Interconnection by no later than May 14 of each year.

B. Pursuant to the terms of Tariff, Schedule 6A and the PJM Manuals, the Market Monitoring Unit will analyze any requested generator black start cost changes on an annual basis and shall notify the Office of the Interconnection of any costs to which it and the Black Start Unit owner have agreed or the Market Monitoring Unit's determination regarding any cost components to which agreement has not been obtained. If a Black Start Unit owner includes a cost component inconsistent with its agreement or inconsistent with the Market Monitoring Unit's determination regarding such cost component, and the Office of the Interconnection accepts the Black Start Service revenue requirements submitted by the Black Start Unit owner, the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and request a determination that would require the Black Start Service generator to utilize the values determined by the Market Monitoring Unit or the Office of the Interconnection or such other values as determined by the Commission.

IV. DEACTIVATION RATES

1. Upon receipt of a notice to deactivate a generating unit under Tariff, Part V from the Office of the Interconnection forwarded pursuant to Tariff, Part V, section 113.1, the Market Monitoring Unit shall analyze the effects of the proposed deactivation with regard to potential market power issues and shall notify the Office of the Interconnection and the generator owner (or, if applicable, its designated agent) if a market power issue has been identified. The Market Monitoring Unit shall provide such notice by the following date: (a) May 31 of the current calendar year, if the Transmission Provider received the notice required pursuant to Tariff, Part V, section 113.1 between January 1 and March 31; (b) August 31 of the current calendar year, if the Transmission Provider received the notice required pursuant to Tariff, Part V, section 113.1 between April 1 and June 30; (c) November 30 of the current calendar year, if the Transmission Provider received the notice required pursuant to Tariff, Part V, section 113.1 between July 1 and September 30; or (d) February 28 of the following calendar year, if the Transmission Provider received the notice required pursuant to Tariff, Part V, section 113.1 between October 1 and December 31. Such notice shall include the specific market power impact resulting from the proposed deactivation of the generating unit, as well as an initial assessment of any steps that could be taken to mitigate the market power impact.

2. The Market Monitoring Unit and the generating unit owner shall attempt to come to agreement on the level of each component included in the Deactivation Avoidable Cost Credit. In the case of cost of service filing submitted to the Commission in alternative to the Deactivation Cost Credit, the Market Monitoring Unit shall indicate to the generating unit owner in advance of filing its views regarding the proposed method or cost components of recovery. The Market Monitoring Unit shall notify the Office of the Interconnection of any costs to which it and the generating unit owner have agreed or the Market Monitoring Unit's determination regarding any cost components to which agreement has not been obtained. If a generating unit owner includes a cost component inconsistent with its agreement or inconsistent with the Market Monitoring Unit's determination regarding such cost components, the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and seek a determination that would require the Generating unit to include an appropriate cost component. This provision is duplicated in Tariff, Part V, section 114 and Tariff, Part V, section 119.

V. OPPORTUNITY COST CALCULATION

The Market Monitoring Unit shall review requests for opportunity cost compensation under Operating Agreement, Schedule 1, section 3.2.3(f-3) and Operating Agreement, Schedule 1, section 3.2.3B(h) and the parallel provisions of Tariff, Attachment K-Appendix, section 3.2.3(f-3) and Tariff, Attachment K-Appendix, section 3.2.
3B(h), discuss with the Office of the Interconnection and individual Market Sellers the amount of compensation, and file exercise its powers to inform Commission staff of its concerns and request a determination of compensation as provided by such sections. These requirements are duplicated in Operating Agreement, Schedule 1, section 3.2.3(f-3) and Operating Agreement, Schedule 1, section 3.2.3B(h) and the paralelle provisions of Tariff, Attachment K-Appendix, section 3.2.3(f-3) and Tariff, Attachment K-Appendix, section 3.2.3B9H).

VI. FTR FORFEITURE RULE

The Market Monitoring Unit shall calculate Transmission Congestion Credits as required under Operating Agreement, Schedule 1, section 5.2.1(b) and Tariff, Attachment K-Appendix, section 5.2.1(b), including the determination of the identity of the Effective FTR Holder and an evaluation of the overall benefits accrued by an entity or affiliated entities trading in FTRs and Virtual Transactions in the Day-ahead Energy Market, and provide such calculations to the Office of the Interconnection. Nothing in this section shall preclude the Market Monitoring Unit from action to recover inappropriate benefits from the subject activity if the amount forfeited is less than the benefit derived by the Effective FTR Holder. If the Office of the Interconnection imposes a forfeiture of the Transmission Congestion Credit in an amount that the Market Monitoring Unit disagrees with, then it may exercise its powers to inform Commission staff of its concerns and request an adjustment.

VII. FORCED OUTAGE RULE

1. The Market Monitoring Unit shall observe offers submitted in the Day-ahead Energy Market to determine whether all or part of a generating unit’s capacity (MW) is designated as Maximum Emergency and (i) such offer in the Real-time Energy Market designates a smaller amount of capacity from that unit as Maximum Emergency for the same time period, and (ii) there is no physical reason to designate a larger amount of capacity as Maximum Emergency in the offer in the Day-ahead Energy Market than in the Real-time Energy Market, the Market Monitoring Unit shall notify the Office of Interconnection.

2. If the Market Monitoring Unit observes that (i) an offer submitted in the Day-ahead Energy market designates all or part of capacity (MW) of a Generating unit as economic maximum that is less than the economic maximum designated in the offer in the Real-time Energy Market, and (ii) there is no physical reason to designate a lower economic maximum in the offer in the Day-ahead Energy Market than in the offer in the Real-time Energy Market, the Market Monitoring Unit shall notify the Office of Interconnection.

VIII. DATA COLLECTION AND VERIFICATION

The Market Monitoring Unit shall gather and keep confidential detailed data on the procurement and usage of fuel to produce electric power transmitted in the PJM Region in order to assist the performance of its duties under Tariff, Attachment M. To achieve this objective, the Market Monitoring Unit shall maintain on its website a mechanism that allows Members to conveniently and confidentially submit such data and develop a manual in consultation with stakeholders that describes the nature of and procedure for collecting data. Members of PJM owning a Generating unit that is located in the PJM Region (including Dynamic Transfer units), or is included in a PJM Black Start Service plan, committed as a Generation Capacity Resource for the current or future Delivery Year, or otherwise subject to a commitment to provide service to PJM, shall provide data to the Market Monitoring Unit.

4. GENERAL PROVISIONS

4.1 Capacity Market Sellers

Only Capacity Market Sellers shall be eligible to submit Sell Offers into the Base Residual Auction and Incremental Auctions. Capacity Market Sellers shall comply with the terms and conditions of all Sell Offers, as established by the Office of the Interconnection in accordance with this Attachment DD, Tariff, Attachment M, Tariff, Attachment M - Appendix and the Operating Agreement.

4.2 Capacity Market Buyers

Only Capacity Market Buyers shall be eligible to submit Buy Bids into an Incremental Auction. Capacity Market Buyers shall comply with the terms and conditions of all Buy Bids, as established by the Office of the Interconnection in accordance with this Attachment DD, Tariff, Attachment M, Tariff, Attachment M - Appendix and the Operating Agreement.

4.3 Agents

A Capacity Market Seller may participate in a Base Residual Auction or Incremental Auction through an Agent, provided that the Capacity Market Seller informs the Office of the Interconnection in advance in writing of the appointment and authority of such Agent. A Capacity Market Buyer may participate in an Incremental Auction through an Agent, provided that the Capacity Market Buyer informs the Office of the Interconnection in advance in writing of the appointment and authority of such Agent. A Capacity Market Buyer or Capacity Market Seller participating in such an auction through an Agent shall be bound by all of the acts or representations of such Agent with respect to transactions in such auction. Any written instrument establishing the authority of such Agent shall provide that any such Agent shall comply with the requirements of this Attachment DD and the Operating Agreement.

4.4 General Obligations of Capacity Market Buyers and Capacity Market Sellers

Each Capacity Market Buyer and Capacity Market Seller shall comply with all laws and regulations applicable to the operation of the Base Residual and Incremental Auctions and the use of these auctions shall comply with all applicable provisions of this Attachment DD, Tariff, Attachment M, Tariff, Attachment M - Appendix, Tariff, Attachment Q, the Operating Agreement, and the Reliability Assurance Agreement, Tariff, Attachment K-Appendix, section 1.4 and the parallel provisions of Operating Agreement, Schedule 1, section 1.4, and all procedures and requirements for the conduct of the Base Residual and Incremental Auctions and the PJM Region established by the Office of the Interconnection in accordance with the foregoing.

4.5 Confidentiality

The following information submitted to the Office of the Interconnection in connection with any Base Residual Auction, Incremental Auction, or Reliability Backstop Auction shall be deemed confidential information for purposes of Operating Agreement, section 18.17, Tariff, Attachment M and Tariff, Attachment M - Appendix: (i) the terms and conditions of the Sell Offers and Buy Bids; and (ii) the terms and conditions of any bilateral transactions for Capacity Resources.

4.6 Bilateral Capacity Transactions

(a) Unit-Specific Internal Capacity Bilateral Transaction Transferring All Rights and Obligations ("Section 4.6(a) Bilateral").

(i) Market Participants may enter into unit-specific internal bilateral capacity contracts for the purchase and sale of title and rights to a specified amount of installed capacity from a specific generating unit or units. Such bilateral capacity contracts shall be for the transfer of rights to capacity to and from a Market Participant and shall be reported to the Office of the Interconnection in accordance with this Attachment DD and the Office of the Interconnection's rules related to its "capacity exchange" tool.

(ii) For purposes of clarity, with respect to all Section 4.6(a) Bilateral transactions, the rights to, and obligations regarding, the capacity that is the subject of the transaction shall pass to the buyer under the contract at the location of the unit and further transactions and rights and obligations associated with such capacity shall be the responsibility of the buyer under the contract. Such obligations include any charges, including penalty charges, relating to the capacity under this Attachment DD. In no event shall the purchase and sale of the rights to capacity pursuant to a Section 4.6(a) Bilateral constitute a transaction with the Office of the Interconnection or PJMSettlement or a transaction in any auction under this Attachment DD.

(iii) All payments and related charges associated with a Section 4.6(a) Bilateral shall be arranged between the parties to the transaction and shall not be billed or settled by the Office of the Interconnection or PJMSettlement. The Office of the Interconnection, PJMSettlement, and the Members will not assume financial responsibility for the failure of a party to perform obligations owed to the other party under a Section 4.6(a) Bilateral reported to the Office of the Interconnection under this Attachment DD.

(iv) With respect to capacity that is the subject of a Section 4.6(a) Bilateral that has cleared an auction under this Attachment DD prior to a transfer, the buyer of the cleared capacity shall be considered in the Delivery Year the party to a transaction with PJMSettlement as Counterparty for the cleared capacity at the Capacity Resource Clearing Price published for the applicable auction.

(v) A buyer under a Section 4.6(a) Bilateral contract shall pay any penalties or charges associated with the capacity transferred under the contract. To the extent the capacity that is the subject of a Section 4.6(a) Bilateral contract has cleared an auction under this Attachment DD prior to a transfer, then the seller under the contract also shall guarantee and indemnify the Office of the Interconnection, PJMSettlement, and the Members for the buyer's obligation to pay any penalties or charges associated with the capacity and for which payment is not made to PJMSettlement by the buyer as determined by the Office of the Interconnection. All claims regarding a default of a buyer to a seller under a Section 4.6(a) Bilateral contract shall be resolved solely between the buyer and the seller.

(vi) To the extent the capacity that is the subject of the Section 4.6(a) Bilateral transaction already has cleared an auction under this Attachment DD, such bilateral capacity transactions shall be subject to the prior consent of the Office of the Interconnection and its determination that sufficient credit is in place for the buyer with respect to the credit exposure associated with such obligations.

(b) Bilateral Capacity Transaction Transferring Title to Capacity But Not Transferring Performance Obligations ("Section 4.6(b) Bilateral").

(i) Market Participants may enter into bilateral capacity transactions for the purchase and sale of a specified megawatt quantity of capacity that has cleared an auction pursuant to this Attachment DD. The parties to a Section 4.6(b) Bilateral transaction shall identify (1) each unit from which the transferred megawatts are being sold, and (2) the auction in which the transferred megawatts cleared. Such bilateral capacity transactions shall transfer title and all rights with respect to capacity and shall be reported to the Office of the Interconnection on an annual basis prior to each Delivery Year in accordance with this Attachment DD and pursuant to the Office of the Interconnection's rules related to its "capacity exchange" tool. Reported transactions with respect to a unit will be accepted by the Office of the Interconnection only to the extent that the total of all bilateral sales from the reported unit (including Section 4.6(a) Bilaterals, Section 4.6(b) Bilaterals, and Locational UCAP bilaterals) do not exceed the unit's cleared unforced capacity.

(ii) For purposes of clarity, with respect to all Section 4.6(b) Bilateral transactions, the rights to the capacity shall pass to the buyer at the location of the unit(s) specified in the reported transaction. In no event shall the purchase and sale of the rights to capacity pursuant to a Section 4.6(b) Bilateral constitute a transaction with PJMSettlement or the Office of the Interconnection or a transaction in any auction under this Attachment DD.

(iii) With respect to a Section 4.6(b) Bilateral, the buyer of the cleared capacity shall be considered in the Delivery Year the party to a transaction with PJMSettlement as Coutnerparty for the cleared capacity at the Capacity Resource Clearing Price published for the applicable auction; provided, however, with respect to all Section 4.6(b) Bilateral transactions, such transactions do not effect a novation of the seller's obligations to make RPM capacity available to PJM pursuant to the terms and conditions originally agreed to by the seller; provided further, however, the buyer shall indemnify PJMSettlement, the LLC, and the Members for any failure by a seller under a Section 4.6(b) Bilateral to meet any resulting obligations, including the obligation to pay deficiency penalties and charges owed to PJMSettlement, associated with the capacity.

(iv) All payments and related charges associated with a Section 4.6(b) Bilateral shall be arranged between the parties to the contract and shall not be billed or settled by the Office of the Interconnection or PJMSettlement. The Office of the Interconnection, PJMSettlement, and the Members will not assume financial responsibility for the failure of a party to perform obligations owed to the other party under a Section 4.6(b) Bilateral capacity contract reported to the Office of the Interconnection under this Attachment DD.

(v) All claims regarding a default of a buyer to a seller under a Section 4.6(b) Bilateral shall be resolved solely between the buyer and the seller.

(c) Locational UCAP Bilateral Transactions Between Capacity Sellers.

(i) Market Participants may enter into Locational UCAP bilateral transactions which shall be reported to the Office of the Interconnection in accordance with this Attachment DD and the LLC's rules related to its "capacity exchange" tool.

(ii) For purposes of clarity, with respect to all Locational UCAP bilateral transactions, the rights to the Locational UCAP that are the subject of the Locational UCAP bilateral transaction shall pass to the buyer under the Locational UCAP bilateral contract subject to the provisions of Tariff, Attachment DD, section 5.3A. In no event, shall the purchase and sale of Locational UCAP pursuant to a Locational UCAP bilateral transaction constitute a transaction with the Office of the Interconnection or PJMSettlement, or a transaction in any auction under this Attachment DD.

(iii) A Locational UCAP Seller shall have the obligation to make the capacity available to PJM in the same manner as capacity that has cleared an auction under this Attachment DD and the Locational UCAP Seller shall have all obligations for charges and penalties associated with the capacity that is the subject of the Locational UCAP bilateral contract; provided, however, the buyer shall indemnify PJMSettlement, the LLC, and the Members for any failure by a seller to meet any resulting obligations, including the obligation to pay deficiency penalties and charges owed to PJMSettlement, associated with the capacity. All claims regarding a default of a buyer to a seller under a Locational UCAP bilateral contract shall be resolved solely between the buyer and the seller.

(iv) All payments and related charges for the Locational UCAP associated with a Locational UCAP bilateral contract shall be arranged between the parties to such bilateral contract and shall not be billed or settled by the Office of the Interconnection or PJMSettlement. The LLC, PJMSettlement, and the Members will not assume financial responsibility for the failure of a party to perform obligations owed to the other party under a Locational UCAP bilateral contract reported to the Office of the Interconnection under this Attachment DD.

(d) The bilateral transactions provided for in this section 4.6 shall be for the physical transfer of capacity to or from a Market Participant and shall be reported to and coordinated with the Office of the Interconnection in accordance with this Attachment DD and pursuant to the Office of the Interconnection's rules relating to its "capacity exchange" tool. Bilateral transactions that do not contemplate the physical transfer of capacity to and from a Market Participant are not subject to this Attachment DD and shall not be reported to and coordinated with the Office of the Interconnection.

(e) Effective with the 2022/2023 Delivery Year, any bilateral transaction provided for in this section 4.6 for replacement capacity shall be given no effect in satisfying the buyer's obligations under this Attachment DD to the extent that the resource that is the subject of the transaction is a Capacity Resource with State Subsidy for which the Capacity Market Seller has not elected to forego receipt of any State Subsidy for the relevant Delivery Year and does not qualify for one of the categorical exemptions described in Tariff, Attachment DD, sections 5.14(h-1)(5) through 5.14(h-1)(8) and the purchased capacity is then used to replace capacity from a Capacity Resource that (1) is not a Capacity Resource with State Subsidy or (2) is a Capacity Resource with State Subsidy for which the Capacity Market Seller elected the competitive exemption pursuant Tariff, Attachment DD, section 5.14(h-1)(4) or reported that it will forego receipt of any State Subsidy for the relevant Delivery Year, all as in accordance with the PJM Manuals.

(f) For the 2025/2026 Delivery Year and all subsequent Delivery Years, Market Participants may adjust the expected performance of a Capacity Resource by entering into a bilateral capacity obligation transaction for the purchase and sale of a specified megawatt quantity of committed capacity that is subject to the performance obligations and provisions of Tariff, Attachment DD, section 10A ("PAI Obligation Transfer"). The seller of the PAI Obligation Transfer transaction has a Performance Assessment Interval obligation on a resource that will be transferred to and received by the buyer's resource as a result of the transaction.

(i) PAI Obligation Transfers shall be reported to the Office of the Interconnection in accordance with this Attachment DD and the Office of the Interconnection's rules related to its "capacity exchange" tool, where the parties in such transaction shall identify (1) the transferring resource of the seller from which the megawatts are being sold, (2) the megawatt quantity of committed capacity to be transferred, (3) the effective time period for which the PAI Obligation Transfer applies, which may be set on an interval basis, and (4) the receiving Capacity Resource of the buyer that will assume the performance obligation of the transferred capacity. Such transactions must be reported and approved by both parties prior to the start of the effective time period of the transfer.

(ii) The effect of a PAI Obligation Transfer is to modify the committed capacity and resulting expected performance of the transferring and receiving resources when assessing the performance shortfall or bonus during a Performance Assessment Interval within Tariff, Attachment DD, section 10A, where the transferring resource will have a reduction in expected performance and the receiving resource will have an increase in expected performance during Performance Assessment Intervals that occur within the effective time period of the transfer. PAI Obligation Transfers do not affect in any way the capacity rights and obligations of the parties and reported resources beyond Tariff, Attachment DD, section 10A.

(iii) The performance obligations of the transferred capacity and any associated Non-Performance Charges under Tariff, Attachment DD, section 10A shall pass to the buyer; provided, however, the seller shall guarantee and indemnify the Office of the Interconnection, PJMSettlement, and the Members for any failure by the buyer to pay any non-performance charges owed to PJMSettlement associated with the transferred capacity.

(iv) For a PAI Obligation Transfer to be accepted by the Office of the Interconnection and take effect for a Performance Assessment Interval, the following criteria must be satisfied, as further described in the PJM Manuals:

(A) The receiving resource reported in the PAI Obligation Transfer must provide the same locational value of capacity (with consideration of remaining import capability into LDAs) as the transferring resource, and both resources must be included in the area of the Performance Assessment Interval; and

(B) The resulting quantity of capacity that is subject to performance obligations under this Tariff, Attachment DD, section 10A on the receiving Capacity Resource reported in the PAI Obligation Transfer shall not exceed the installed capacity or Capacity Interconnection Rights of the receiving resource.

(v) All payments and related charges associated with a PAI Obligation Transfer shall be arranged between the parties to the transaction and shall not be billed or settled by the Office of the Interconnection or PJMSettlement. The Office of the Interconnection, PJMSettlement, and the Members will not assume financial responsibility for the failure of a party to perform obligations owed to the other party under a PAI Obligation Transfer reported to 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 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 Tariff, Attachment DD, section 5.12(a) and section 5.14(a) above.

(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) above; 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 Tariff, Attachment DD, section 5.12(a), 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) above that is entitled to compensation pursuant to section 5.14(b) above; 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) above 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) above. Other capacity resources that clear the BRA in such LDA receive the Capacity Resource Clearing Price as determined in section 5.14(a) above.

6. The failure to submit a Sell Offer consistent with section 5.14(c)(i)-(iii) above 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) above 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 Tariff, Attachment DD, section 5.10(a)(ii).

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 Tariff, Attachment DD, 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 Tariff, Attachment DD, section 5.14B, Tariff, Attachment DD, section 5.14C, Tariff, Attachment DD, section 5.14D, Tariff, Attachment DD, section 5.14E and Tariff, Attachment DD, section 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 Resource Make-Whole Payments; and 4) 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 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 (4) 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 New Generation Capacity Resources that are not Capacity Resources with State Subsidy for up to the 2022/2023 Delivery Year.

(1) The provisions of this section 5.14(h) shall not be effective after the 2022/2023 Delivery Year. 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 Tariff, Attachment DD, section 5.10(a)(iv)(A) of this Attachment. This section only applies to new Generation Capacity Resources that do not receive or are not entitled to receive a State Subsidy, meaning that such resources are not Capacity Resources with State Subsidy. To the extent a new Generation Capacity Resource is a Capacity Resource with State Subsidy, then the provisions in Tariff, Attachment DD, section 5.14(h-1) apply.

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	128,990	130,300

CC $/MW-yr	185,700	176,000	172,600	179,400

(2) 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 Tariff, Attachment DD, 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 the 2022/2023 Delivery Year, for purposes of this provision, the net energy and ancillary services revenue estimate for a combustion turbine generator shall be that determined by Tariff, Attachment DD, section 5.10(a)(v-1)(A), provided that the energy and ancillary services 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 6.501 MMbtu/MWh, the variable operations and maintenance expenses for such resource shall be $2.11 per MWh, a 10% adder will not be included in the energy offer, and the reactive service revenues shall be $3,350 per MW-year.

(4) Any Sell Offer that is based on either (i) or (ii), and (iii):

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;

iii) in any LDA for which a separate VRR Curve is established for use in the Base Residual Auction for the Delivery Year relevant to the RPM Auction in which such offer is submitted, and that is less than 90 percent of the applicable Net Asset Class Cost of New Entry or, if there is no applicable Net Asset Class Cost of New Entry, less than 70 percent of the Net Asset Class Cost of New Entry for a combustion turbine generator as provided in subsection (h)(1) above shall be set to equal 90 percent of the applicable Net Asset Class Cost of New Entry (or set equal to 70 percent of such cost for a combustion turbine, where there is no otherwise applicable net asset class figure), unless the Capacity Market Seller obtains the prior determination from the Office of the Interconnection described in subsection (5) hereof. This provision applies to Sell Offers submitted in Incremental Auctions conducted after December 19, 2011, provided that the Net Asset Class Cost of New Entry values for any such Incremental Auctions for the 2012-13 or 2013-14 Delivery Years shall be the Net Asset Class Cost of New Entry values posted by the Office of the Interconnection for the Base Residual Auction for the 2014-15 Delivery Year.

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

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

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

The request also shall identify all revenue sources relied upon in the Sell Offer to offset the claimed fixed costs, including, without limitation, long-term power supply contracts, tolling agreements, or tariffs on file with state regulatory agencies, and shall demonstrate that such offsetting revenues are consistent, over a reasonable time period identified by the Capacity Market Seller, with the standard prescribed above.

For the 2022/2023 Delivery Year, in making such demonstration, the Capacity Market Seller may rely upon revenues projected by well defined, forward-looking dispatch models, designed to generally follow the rules and processes of PJM's energy and ancillary services markets. Such models must utilize publicly available forward prices for electricity and fuel in the PJM Region. Any modifications made to the forward electricity and fuel prices must similarly use publicly available data. Alternative forward prices for fuel may be used if accompanied by contractual evidence showing the applicability of the alternative fuel price. Where forward fuel markets are not available, publicly available estimates of future fuel prices may be used. The model shall also contain estimates of variable operation and maintenance costs, which may include Maintenance Adders, and emissions allowance prices. Documentation for net revenues also must 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, capacity factors and ancillary service capabilities.

In the alternative, the Capacity Market Seller may request that the Market Monitoring Unit, subject to acceptance by the Office of Interconnection, produce a resource-specific Energy & Ancillary Services Offset value for such resource using the Forward Hourly LMPs, Forward Hourly Ancillary Service Prices, and either Forward Daily Natural Gas Prices for combustion turbines and combined cycle resources, or forecasted fuel prices for other resource types, and plant parameters and capability information specific to the dispatch of the resource, as outlined above. In addition to the documentation identified herein and in the PJM Manuals, the Capacity Market Seller shall provide any additional supporting information reasonably requested by the Office of the Interconnection or the Market Monitoring Unit to evaluate the Sell Offer. Requests for additional documentation will not extend the deadline by which the Office of the Interconnection or the Market Monitoring Unit must provide their determinations of the Minimum Offer Price Rule exception request.

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

iv) The Market Monitoring Unit shall review the information and documentation in support of the request and shall provide its findings whether the proposed Sell Offer is acceptable, in accordance with the standards and criteria hereunder, in writing, to the Capacity Market Seller and the Office of the Interconnection by no later than ninety (90) days prior to the commencement of the offer period for such auction. The Office of the Interconnection shall also review all exception requests and documentation and shall provide in writing to the Capacity Market Seller, and the Market Monitoring Unit, its determination whether the requested Sell Offer is acceptable and if not it shall calculate and provide to such Capacity Market Seller, a minimum Sell Offer based on the data and documentation received, by no later than sixty-five (65) days prior to the commencement of the offer period for the relevant RPM Auction. If the Office of the Interconnection determines that the requested Sell Offer is acceptable, the Capacity Market Seller Shall notify the Market Monitoring Unit and the Office of the Interconnection, in writing, of the minimum level of Sell Offer to which it agrees to commit by no later than sixty (60) days prior to the commencement of the offer period for the relevant RPM Auction.

h-1) Minimum Offer Price Rule for Capacity Resources with State Subsidy for the 2022/2023 Delivery Year.

(1) **General Rule.** The provisions of this section 5.14(h-1) shall not be effective after the 2022/2023 Delivery Year. For the 2022/2023 Delivery Year, any Sell Offer based on either a New Entry Capacity Resource with State Subsidy 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 that qualifies for any of the exemptions defined in Tariff, Attachment DD, sections 5.14(h-1)(4)-(8), the Sell Offer for such resource shall not be limited by the MOPR Floor Offer Price, unless otherwise specified.

(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 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, 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. 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. Notwithstanding, if a Capacity Market Seller submits a timely resource-specific exception pursuant to Tariff, Attachment DD, section 5.14(h-1)(3) for the relevant Delivery Year, and PJM approves the resource-specific MOPR Floor Offer Price, then the Capacity Market Seller may use such floor price regardless of whether it timely certified whether or not the resource is a Capacity Resource with State Subsidy.

(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 Renewable Portfolio Standard 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 material change in status as a Capacity Resource with State Subsidy within 30 days of such material change, unless such material change occurs within 30 days of the commencement of the offer period of any RPM Auction for the 2022/2023 Delivery Year, in which case the Market Seller must notify PJM no later than 5 days prior to the commencement of the offer period of any RPM Auction for the 2022/2023 Delivery Year. Nothing in this provision shall supersede the requirement for all Capacity Market Sellers to certify to the Office of Interconnection whether its resource meets the criteria of a Capacity Resource with State Subsidy pursuant to Tariff, Attachment DD, section 5.14(h-1)(1)(C)(i).

(2) **Minimum Offer Price Rule.** Any Sell Offer for a New Entry Capacity Resource with State Subsidy 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-1)(4)-(8), shall have an offer price no lower than the applicable MOPR Floor Offer Price, unless the applicable MOPR Floor Offer Price is higher than the applicable Market Seller Offer Cap, in which circumstance the Capacity Resource with State Subsidy must seek a resource-specific value determined in accordance with the resource-specific MOPR Floor Offer Price process to participate in an RPM Auction.

(A) New Entry MOPR Floor Offer Price. For a New Entry Capacity Resource with State Subsidy 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-1)(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, 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	$271
Tracking Solar PV	$290
Onshore Wind	$420
Offshore Wind	$1,155
Battery Energy Storage	$532
Diesel Backed Demand Resource	$254

The gross cost of new entry values in the table above are expressed in dollars per MW-day in terms of nameplate megawatts. For purposes of submitting a Sell Offer, the gross cost of new entry values must be converted to a net cost of new entry by subtracting the estimated net energy and ancillary service revenues, as determined below, from the gross cost of new entry. However, the resultant net cost of new entry of the battery energy storage resource type in the table above must be multiplied by 2.5. The net cost of new entry based on nameplate capacity is then converted to Unforced Capacity ("UCAP") MW-day. For Delivery Years through the 2022/2023 Delivery Year, to determine the applicable UCAP MW-day value, the net cost of new entry is adjusted as follows: for thermal generation resource types and battery energy storage resource types, the applicable class average EFORd; for wind and solar generation resource types, the applicable class average capacity value factor; or for Demand Resources and Energy Efficiency Resources, the Forecast Pool Requirement, as applicable to the relevant RPM Auction. For the

2023/2024 Delivery Year and subsequent Delivery Years, to determine the applicable UCAP MW-day value, the net cost of new entry is adjusted as follows: for thermal generation resource types, the applicable class average EFORd; for battery storage, wind, and solar resource types, the applicable ELCC Class Rating; or for Demand Resources and Energy Efficiency Resources, the Forecast Pool Requirement, as applicable to the relevant RPM Auction. The resulting default New Entry MOPR Floor Offer price in UCAP/MW-day terms shall be applied to each MW offered for the Capacity Resource regardless of the actual Sell Offer quantity and regardless of whether the Sell Offer is for a Seasonal Capacity Performance Resource.

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.

For generation-backed Demand Resources that are not powered by diesel generators, the default New Entry MOPR Floor Offer Price shall be the default New Entry MOPR Floor Offer Price applicable to their technology type. Generation-backed Demand Resources using a technology type 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 in Tariff, Attachment DD, section 5.14(h-1)(3) below to participate in an RPM Auction.

The default gross cost of new entry for Energy Efficiency Resources shall be $644/ICAP MW-Day, which shall be offset by projected wholesale energy savings, as well as transmission and distribution savings of $95/ICAP MW-Day, to determine the default New Entry MOPR Floor Offer Price (Net Cost of New Entry), where the projected wholesale energy savings are determined utilizing the cost and performance data of relevant programs offered by representative energy efficiency programs with sufficiently detailed publicly available data. The wholesale energy savings, in $/ICAP MW-day, shall be calculated prior to each RPM Auction and be equal to the average annual energy savings of 6,221 MWh/ICAP MW times the weighted average of the annual real-time Forward Hourly LMPs of the Zones of the representative energy efficiency programs, where the weighting is developed from the annual energy savings in the relevant Zones, divided by 365.

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, combine cycle, and generation-backed Demand 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 shall be the average of the net energy and ancillary services revenues that the resource is projected to receive from the PJM energy and ancillary service markets for the applicable Delivery Year from three separate simulations, with each such simulation using forward prices shaped using historical data from one of each of the three consecutive calendar years preceding the time of the determination for the RPM Auction to take account of year-to-year variability in such hourly shapes. Each net energy and ancillary services revenue simulation shall be conducted in accordance with the following and the PJM Manuals:

(i) for nuclear resource type, the net energy and ancillary services revenue estimate for each Zone shall be determined by the gross energy market revenue determined by the product of [average annual day-ahead Forward Hourly LMPs for such Zone, 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 reactive services revenue of $3,350/MW-year;

(ii) for coal resource type, the net energy and ancillary services revenue estimate for each Zone shall be determined by the Projected EAS 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 day-ahead and real-time Forward Hourly LMPs for such Zone and Forward Hourly Ancillary Service Prices, and daily forecasted coal prices, as set forth in the PJM Manuals, plus reactive services revenue of $3,350/MW-year;

(iii) for combustion turbine resource type, the net energy and ancillary services revenue estimate for each Zone shall be determined in a manner consistent with the methodology described in Tariff, Attachment DD, section 5.10(a)(v-1)(B) for the Reference Resource combustion turbine.

(iv) for combined cycle resource type, the net energy and ancillary services revenue estimate for each Zone 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 6,501 BTU/kwh, the variable operations and maintenance expenses for such resource, inclusive of Maintenance Adder costs, shall be $2.11/MWh, plus reactive services revenue of $3,350/MW-year.

(v) for solar PV resource type, the net energy and ancillary services revenue estimate for each Zone 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 Forward Hourly LMP for such Zone and applicable to such hour with this product summed across all of the hours of an annual period, plus reactive 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 for each Zone 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 Forward Hourly LMP for such Zone applicable to such hour with this product summed across all of the hours of an annual period, plus reactive services revenue of $3,350/MW-year;

(vii) for offshore wind resource type, the net energy and ancillary services revenue estimate for each Zone shall be determined by the gross energy market revenue equal to the product of [the average annual real-time Forward Hourly LMP for such Zone times 8,760 hours times an assumed annual capacity factor of 45%], plus reactive services revenue of $3,350/MW-year;

(viii) for Capacity Storage Resource, the net energy and ancillary services revenue estimate shall be estimated by the Projected EAS Dispatch of a 1 MW, 4MWh resource, with an 85% roundtrip efficiency, and assumed to be dispatched between 95% and 5% state of charge against day-ahead and real-time Forward Hourly LMPs for such Zone and Forward Hourly Ancillary Service Prices, plus reactive services revenue of $3,350/MW-year; and

(ix) for generation-backed Demand Resource, the net energy and ancillary services revenue estimate shall be zero dollars.

New Entry Capacity Resource with State Subsidy for which there is no default MOPR Floor Offer Price provided in accordance with this section, including hybrid resources, 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.

(i) 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, (a) based on the resource-specific MOPR Floor Offer Price , as determined in accordance with Tariff, Attachment DD, section 5.14(h-1)(3) below, or (b) if available, the default Avoidable Cost Rate for the applicable resource type shown in the table below, net of projected PJM market revenues equal to the resource's net energy and ancillary service revenues for the resource type, as determined in accordance with subsection (ii) below.

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
Diesel-backed Demand Response	$3
Load-backed Demand Response	$0
Energy Efficiency	$0

The default gross Avoidable Cost Rate values in the table above are expressed in dollars per MW-day in terms of nameplate megawatts. For purposes of submitting a Sell Offer, the default Avoidable Cost Rate values must be net of estimated net energy and ancillary service revenues, and then the difference is ultimately converted to Unforced Capacity ("UCAP") MW-day, where the UCAP MW-day value will be determined based on: for Delivery Years through the 2022/2023 Delivery Year, the resource-specific EFORd for thermal generation resource types, resource-specific capacity value factor for solar and wind generation resource types (based on the ratio of Capacity Interconnection Rights to nameplate capacity, appropriately time-weighted for any winter Capacity Interconnection Rights), or the Forecast Pool Requirement for Demand Resources and Energy Efficiency Resources, as applicable to the relevant RPM Auction, and for the 2023/2024 Delivery Year and subsequent Delivery Years, the resource-specific EFORd for thermal generation resource types and on the resource-specific Accredited UCAP value for solar and wind resource types (with appropriate time-weighting for any winter Capacity Interconnection Rights), or the Forecast Pool Requirement for Demand Resources and Energy Efficiency Resources, as applicable to the relevant RPM Auction. The resulting default Cleared MOPR Floor Offer price in UCAP/MW-day terms shall be applied to each MW offered for the Capacity Resource regardless of actual Sell Offer quantity and regardless of whether the Sell Offer is for a Seasonal Capacity Performance Resource.

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.

For generation-backed Demand Resources that are not powered by diesel generators, the default Cleared MOPR Floor Offer Price shall be the default Cleared MOPR Floor Offer Price applicable to their technology type. Generation-backed Demand Resources using a technology type 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 in Tariff, Attachment DD, section 5.14(h-1)(3) below to participate in an RPM Auction.

Cleared Capacity Resources with State Subsidy for which there is no default MOPR Floor Offer Price provided in accordance with this section, including hybrid resources, 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.

(ii) The net energy and ancillary services revenue is equal to forecasted net revenues which shall be determined in accordance with the applicable resource type net energy and ancillary services revenue determination methodology set forth in Tariff, Attachment DD, section 5.14(h-1)(2)(A)(i) through (ix) and using the subject resource's operating parameters as determined in accordance with the PJM Manuals based on (a) offers submitted in the Day-ahead Energy Market and Real-time Energy Market over the calendar year preceding the time of the determination for the RPM Auction; (b) the resource-specific operating parameters approved, as applicable, in accordance with Operating Agreement, Schedule 1, section 6.6(b) and Operating Agreement, Schedule 2 (including any Fuel Costs, emissions costs, Maintenance Adders, and Operating Costs); (c) the resource's EFORd; (d) Forward Hourly LMPs at the generation bus as determined in accordance with Tariff, Attachment DD, section 5.10(a)(v-1)(C)(6); and (e) the resource's stated annual revenue requirement for reactive services; plus any unit-specific bilateral contract. In addition, the following resource type-specific parameters shall be considered; (f) for combustion turbine, combined cycle, and coal resource types: the installed capacity rating, ramp rate (which shall be equal to the maximum ramp rate included in the resource's energy offers over the most recent previous calendar year preceding the determination for the RPM Auction), and the heat rate as determined as the resource's average heat rate at full load as submitted to the Market Monitoring Unit and the Office of the Interconnection, where for combined cycle resources heat rates will be determined at base load and at peak load (e.g., without duct burners and with duct burners), as applicable; (g) for nuclear resource type: an average equivalent availability factor of all PJM nuclear resources to account for refueling outages; (h) for solar and wind resource types: the resource's output profiles for the most recent three calendar years, as available; and (i) for battery storage resource type: the nameplate capacity rating (on a MW / MWh basis).

To the extent the resource has not achieved commercial operation, the operating parameters used in the simulation of the net energy and ancillary service revenues will be based on the manufacturer's specifications and/or from parameters used for other existing, comparable resources, as developed by the Market Monitoring Unit and the Capacity Market Seller, and accepted by the Office of the Interconnection.

A Capacity Market Seller intending to submit a Sell Offer in any RPM Auction for a Cleared Capacity Resource with State Subsidy based on a net energy and ancillary services revenue determination that does not use the foregoing methodology or parameter inputs stated for that resource type shall, at its election, submit a request for a resource-specific MOPR Floor Offer Price for such Capacity Resource pursuant to Tariff, Attachment DD, section 5.14(h-1)(3) below.

(3) Resource-Specific Exception. A Capacity Market Seller intending to submit a Sell Offer in any RPM Auction for a New Entry Capacity Resource with State Subsidy 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. The resource-specific MOPR Floor Offer Price determined under this provision shall be based on the resource-specific EFORd for thermal generation resource types, on the resource-specific Accredited UCAP value for ELCC Resources (where for solar and wind generation resource types the Accredited UCAP shall be appropriately time-weighted for any winter Capacity Interconnection Rights), or the Forecast Pool Requirement for Demand Resources and Energy Efficiency Resources, as applicable to the relevant RPM Auction and shall be applied to each MW offered by the resource regardless of actual Sell Offer quantity and regardless of whether the Sell Offer is for a Seasonal Capacity Performance Resource. 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-1)(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 with State Subsidy, 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 revenues projected by well-defined, forward-looking dispatch models designed to generally follow the rules and processes of PJM's energy and ancillary services market. Such models must utilize publicly available forward prices for electricity and fuel in the PJM Region. Any modifications made to the forward electricity and fuel prices must similarly use publicly available data. Alternative forward prices for fuel may be used if accompanied by contractual evidence showing the applicability of the alternative fuel price. Where forward fuel markets are not available, publicly available estimates of future fuel prices may be used. The model shall also contain estimates of variable operation and maintenance expenses, which may include Maintenance Adders, and emissions allowance prices. Documentation for net revenues also must 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, capacity factors, 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 the alternative, the Capacity Market Seller may request that the Market Monitoring Unit, subject to acceptance by the Office of Interconnection, produce a resource-specific Energy & Ancillary Services Offset value for such resource using the Forward Hourly LMPs, Forward Hourly Ancillary Service Prices and either Forward Daily Natural Gas Prices for combustion turbines and combined cycle resources, or forecasted fuel prices for other resource types, plus plant parameters and capability information specific to the dispatch of the resource, as outlined above. 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 consider all costs associated with the generation unit supporting the Demand Resource, and 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.

(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 shall, 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 revenues projected by well-defined, forward-looking dispatch models designed to generally follow the rules and processes of PJM's energy and ancillary services market. Such models must utilize publicly available forward prices for electricity and fuel in the PJM Region. Any modifications made to the forward electricity and fuel prices must similarly use publicly available data. Alternative forward prices for fuel may be used if accompanied by contractual evidence showing the applicability of the alternative fuel price. Where forward fuel markets are not avaliable, publicly avaliable estimates of future fuel sources may be used. The model shall also contain estimates of variable operation and maintenance expenses, which may include Maintenance Adders, and emissions allowance prices. Documentation for net revenues also must 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, capacity factors, 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.

In the alternative, the Capacity Market Seller may request that the Market Monitoring Unit, subject to acceptance by the Office of Interconnection, produce a resource-specific Energy & Ancillary Services Offset value for such resource using the Forward Hourly LMPs, Forward Hourly Ancillary Service Prices and either Forward Daily Natural Gas Prices for combustion turbines and combined cycle resources, or forecasted fuel prices for other resource types, plus plant parameters and capability information specific to the dispatch of the resource, as outlined above. 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 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 all costs associated with the generation unit supporting the Demand Resource, and 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.

(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 under this subsection 5.14(h-1) 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 unless the Self-Supply Entity certifies, subject to PJM and Market Monitor review, that the Capacity Resource will not accept a State Subsidy, including any financial benefit that is the result of being owned by a regulated utility, such that retail ratepayers are held harmless, (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, or (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 (unless the underlying Capacity Resource that is the subject of a bilateral transaction has not received, is not receiving, and is not entitled to receive any State Subsidy except those that are assigned (i.e., renewable energy credits) to the off-takers of a bilateral transaction and the Capacity Market Seller of such Capacity Resource can demonstrate and certify that the Capacity Market Seller's rights and obligations of its share of the capacity, energy, and assignable State Subsidy associated with the underlying Capacity Resource are in pro rata shares). A new Generation Capacity Resource that is a Capacity Resource with State Subsidy may elect the competitive exemption; however, in such instance, the applicable MOPR Floor Offer Price will be determined in accordance with the minimum offer price rules for certain new Generation Capacity Resources as provided in Tariff, Attachment DD, section 5.14(h), which apply the minimum offer price rule to the new Generation Capacity Resources located in an LDA where a separate VRR Curve is established as provided in Tariff, Attachment DD, section 5.14(h)(4).

(B) 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.

(5) Self-Supply Entity exemption. A Capacity Resource that was owned, or bilaterally contracted, by a Self-Supply Entity on December 19, 2019, shall be exempt from the Minimum Offer Price Rule if such Capacity Resource remains owned or bilaterally contracted by such Self-Supply Entity and 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 wholesale market participation agreement executed by the interconnection customer 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 wholesale market participation agreement filed by PJM with the Commission on or before December 19, 2019.

(6) Renewable Portfolio Standard Exemption. A Capacity Resource with State Subsidy 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 as of December 19, 2019 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 wholesale market participation agreement executed by the interconnection customer 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 wholesale market participation agreement filed by PJM with the Commission on or before December 19, 2019.

(7) Demand Resource and Energy Efficiency Resource Exemption.

(A) 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:

(i) has successfully cleared an RPM Auction prior to December 19, 2019. For purposes of this subsection (A), individual customer location registrations 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

(ii) has completed registration on or before December 19, 2019; or

(iii) 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).

(B) All registered locations that qualify for the Demand Resource and Energy Efficiency Resource exemption shall continue to remain exempt even if the MW of nominated capacity increases between RPM Auctions unless any MW increase in the nominated capacity is due to an investment made for the sole purpose of increasing the curtailment capability of the location in the capacity market. In such case, the MW of increased capability will not be qualified for the Demand Resource and Energy Efficiency Resource exemption.

(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 wholesale market participation agreement executed by the interconnection customer 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 wholesale market participation agreement 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.

h-2) Minimum Offer Price Rule Effective with the 2023/2024 Delivery Year

(1) **Certification Requirement.**

(A) By no later than one hundred and fifty (150) days prior to the commencement of the offer period of any RPM Auction conducted for the 2024/2025 Delivery Year and all subsequent Delivery Years, and by the date posted on the PJM website for the 2023/2024 Delivery Year, each Capacity Market Seller must certify to the Office of Interconnection for each Generation Capacity Resource the Capacity Market Seller intends to offer into the RPM Auction, in accordance with the PJM Manuals:

(i) whether or not the Generation Capacity Resource is receiving or expected to receive Conditioned State Support under any legislative or other governmental policy or program that has been enacted or effective at the time of the certification; and

(ii) whether or not the Capacity Market Seller acknowledges and understands that the Exercise of Buyer-Side Market Power is not permitted in RPM Auctions, and does not intend to submit a Sell Offer for their Generation Capacity Resource as an Exercise of Buyer-Side Market Power.

(B) All Capacity Market Sellers shall be responsible for the accuracy of each certification and its conformance with the Tariff irrespective of any guidance developed by the Office of the Interconnection and the Market Monitoring Unit.

(C) Once a Capacity Market Seller has certified whether or not a Generation Capacity Resource is receiving or expected to receive Conditioned State Support, the certification requirements in subsection (A)(i) above do not apply and the status of such Generation Capacity Resource will remain unchanged unless and until the Capacity Market Seller (or a subsequent Capacity Market Seller of the underlying resource) that owns or controls such Generation 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 Generation Capacity Resource's material change in status regarding whether such resource is receiving or expected to receive Conditioned State Support within 30 days of such material change. Nothing in this provision shall supersede the requirement for all Capacity Market Sellers to certify to the Office of Interconnection pursuant to Tariff, Attachment DD, section 5.14(h-2)(1)(A)(ii).

(2) **Determining Generation Capacity Resources Subject to the Minimum Offer Price Rule.**

(A) Conditioned State Support.

(i) If the Office of the Interconnection reasonably believes a government policy or program would provide Conditioned State Support or a Capacity Market Seller certifies that it is receiving or is expected to receive Conditioned State Support associated with a given Generation Capacity Resource, the Office of Interconnection shall submit, pursuant to section 205 of the Federal Power Act, 16 U.S.C. § 824d, a filing at FERC indicating the Office of the Interconnection's intent to classify the government policy or program from which that support is derived as Conditioned State Support (and adding such policy or program to the list in Tariff, Attachment DD-3) and apply the Minimum Offer Price Rule to each Generation Capacity Resource reasonably expected to receive such Conditioned State Support. If FERC has already ruled on whether a specific government program or policy constitutes Conditioned State Support and such policy or program is listed in Tariff, Attachment DD-3, the Office of the Interconnection shall not be required to submit the filing described in the preceding sentence.

(ii) Government policies or programs that do not provide payments or other financial benefit outside of PJM markets and do not provide payment or other financial benefit in exchange for the sale of a FERC-jurisdictional product conditioned on clearing in any RPM Auction do not constitute Conditioned State Support. Examples of such government policies that do not constitute Conditioned State Support may include, but are not limited to: policies designed to procure, incent, or require environmental attributes, whether bundled or unbundled (e.g., Renewable Energy Credits, Zero Emission Credits; Regional Greenhouse Gas Initiative); economic development programs and policies; tax incentives; state retail default service auctions; policies or programs that provide incentives related to fuel supplies; 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., Cross-State Air Pollution

Rule). In addition, Conditioned State Support shall not be determined solely based on the business model of the Capacity Market Seller, such that the fact that a Self-Supply Entity is the Capacity Market Seller, for example, is not a basis for determining Conditioned State Support.

(iii) Upon FERC acceptance (whether by order or operation of law) that a government policy or program or contract with a state entity constitutes Conditioned State Support, a Generation Capacity Resource for which a Capacity Market Seller certifies pursuant to Tariff, Attachment DD, section 5.14(h-2)(1)(A)(i) that it is receiving Conditioned State Support or is reasonably expected to receive such Conditioned State Support, as identified by the Office of the Interconnection, with the advice and input of the Market Monitoring Unit, will be subject to the provisions of the Minimum Offer Price Rule.

(B) Exercise of Buyer-Side Market Power

(i) If a Capacity Market Seller does not certify that it acknowledges the prohibition of the Exercise of Buyer Side Market Power and the Capacity Market Seller intends to exercise Buyer-Side Market Power for this Generation Capacity Resource, then the underlying Capacity Resource shall be subject to the MOPR pursuant to Tariff, Attachment DD, section 5.14(h-2)(1)(A)(i). If the Office of the Interconnection and/or the Market Monitoring Unit reasonably suspects that a certification submitted under Tariff, Attachment DD, section 5.14(h-2)(1)(A)(ii) contains fraudulent or material misrepresentations such that the Capacity Market Seller's Generation Capacity Resource may be the subject of a Sell Offer that would be an Exercise of Buyer-Side Market Power or otherwise reasonably suspects that a Generation Capacity Resource may be the subject of a Sell Offer that would be an Exercise of Buyer-Side Market Power, the Office of the Interconnection and/or the Market Monitoring Unit shall initiate a fact-specific review into the facts and circumstances regarding the Generation Capacity Resource and whether the Capacity Market Seller has the ability and incentive to exercise Buyer-Side Market Power with respect to such Generation Capacity Resource. During such fact-specific review, the Capacity Market Seller will have the opportunity to explain and justify why a Sell Offer for the Generation Capacity Resource would not be an Exercise of Buyer-Side Market Power. The Office of the Interconnection and/or the Market Monitoring Unit shall notify the Capacity Market Seller of the bases for inquiry and initiation of review at least 135 days in advance of the RPM Auction conducted for the 2024/2025 Delivery Year and all subsequent Delivery Years, and by the date posted on the PJM website for the 2023/2024 Delivery Year.

In initiating a review, the Office of the Interconnection and/or the Market Monitoring Unit shall provide the affected Capacity Market Seller, in writing, the basis for its inquiry, including, but not limited to, the Generation Capacity Resource(s), and the purported beneficiary of any price suppression. The Office of the Interconnection and/or the Market Monitoring Unit may request from the Capacity Market Seller additional information and documentation that is reasonably related to the basis for its inquiry, provided that, the Office of the Interconnection and the Market Monitoring Unit shall confer with the Capacity Market Seller in advance of any such requests. The Capacity Market Seller shall provide any additional supporting information and documentation requested by the Office of the Interconnection and/or the Market Monitoring Unit, and any other information and documentation the Capacity Market Seller believes may justify the conduct or action in question as not representing an Exercise of

Buyer-Side Market Power, within 15 days or other such timeline as agreed to in writing by the Office of the Interconnection, Market Monitoring Unit and Capacity Market Seller.

The fact-specific review will determine, as necessary, whether a Capacity Market Seller has the ability and incentive to submit a Sell Offer for the Generation Capacity Resource that could be an Exercise of Buyer-Side Market Power, as follows:

(a) To determine whether a Capacity Market Seller may have Buyer Side Market Power associated with the Generation Capacity Resource for the applicable RPM Auction, the Office of the Interconnection and/or the Market Monitoring Unit will perform ex-ante testing to determine the extent to which a shift in the supply curve by a number of megawatts equal to the size of the Generation Capacity Resource would affect RPM Auction clearing prices, where such analysis would reflect expected supply and demand conditions in the region of the market clearing prices and quantities in recent RPM Auctions, would reflect whether the relevant LDAs have been constrained in recent RPM Auctions, and would reflect reasonably expected material changes in an LDA including the modeling of the LDA and expected changes in supply and demand for the applicable Delivery Year. To the extent the foregoing analyses show that the Generation Capacity Resource would have a material effect on RPM Auction clearing prices, the Capacity Market Seller shall be deemed to have the ability to exercise Buyer Side Market Power.

(b) To determine whether the Capacity Market Seller's submission of a Sell Offer at any given price level for such Generation Capacity Resource may constitute an Exercise of Buyer-Side Market Power, the Office of the Interconnection and/or the Market Monitoring Unit shall perform ex-ante testing to determine whether, given the ability to suppress prices identified in the relevant LDAs and the PJM Region, such price suppression would be economically beneficial to the Capacity Market Seller by comparing its expected cost with its economic benefit, and where the expected cost shall reflect the excess economic costs of the resource above expected market revenues, and the expected benefit shall reflect the expected cost savings to the expected net short position (based on estimated capacity obligations and owned and contracted capacity measured on a three-year average basis for the three years starting with the first day of the Delivery Year associated with the RPM Auction in which the Generation Capacity Resource is being offered) in the relevant LDAs and RTO multiplied by the price change resulting from offering the resource uneconomically. In this analysis, the Office of Interconnection and/or the Market Monitoring Unit shall consider whether any capacity obligations in which the capacity costs based on RPM Auction clearing prices are directly passed through to load and consider whether the price of any contracted capacity passes through RPM Auction clearing prices. If the expected benefit outweighs the expected cost, the Capacity Market Seller shall be deemed to have the incentive to exercise Buyer Side Market Power. If a resource offer can be justified, economically or otherwise, without consideration of the benefit to the Capacity Market Seller of the suppressed prices, the Capacity Market Seller shall be deemed not to have the incentive to exercise Buyer Side Market Power with respect to that resource. Out-of-market compensation (such as from renewable energy credits and zero emission credits) that are not tied to either Conditioned State Support or a bilateral contract that directs the submission of an offer to lower market clearing prices may be used to support the economics of the resource under review.

(ii) The following nonexhaustive list of circumstances would preclude an inquiry into or determination regarding an Exercise of Buyer-Side Market Power in the course of a review initiated pursuant to subsection (i) above: (a) the Generation Capacity Resource is a merchant generation supply resources that is not contracted to an entity with a Load Interest; (b) the Generation Capacity Resource is acquired by or under the contractual control of the Capacity Market Seller through a competitive and non-discriminatory procurement process open to new and existing resources; or (c) the Generation Capacity Resource is owned by or bilaterally contracted to a Self-Supply Seller and such resource is demonstrated as consistent with or included in the Self-Supply Seller's long-range resource plan (e.g., a long-range hedging plan) that is approved or otherwise reviewed and accepted by the RERRA, provided that any such plan approval or contracts do not direct the submission of an uneconomic offer to deliberately lower market clearing prices or for the Capacity Market Seller to otherwise perform an Exercise of Buyer-Side Market Power. In addition, to the extent a Generation Capacity Resource may receive compensation in support of characteristics aligned with well-demonstrated customer preferences, such compensation shall not, in and of itself, be a basis for the determination of Buyer-Side Market Power.

(iii) Based on the foregoing tests and fact-specific review, including the facts and circumstances of the Generation Capacity Resource, the Office of the Interconnection, with the advice and input of the Market Monitoring Unit, shall determine whether a Generation Capacity Resource may be the subject of a Sell Offer that would be an Exercise of Buyer-Side Market Power. If the Office of the Interconnection, with the advice and input of the Market Monitoring Unit, determines that a Generation Capacity Resource may be the subject of a Sell Offer that would be an Exercise of Buyer-Side Market Power or the Capacity Market Seller certifies that it intends to exercise Buyer-Side Market Power, then such resource will be subject to the provisions of the Minimum Offer Price Rule. If the resource will be subject to the provisions of the Minimum Offer Price Rule, the Office of the Interconnection shall include in the notice a written explanation for such determination. A Capacity Market Seller that is dissatisfied with the Office of the Interconnection's determination of whether a given Generation Capacity Resource is subject to the Minimum Offer Price Rule 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 its determination hereunder unless FERC by order directs otherwise.

(C) Failure to timely submit a certification. Any Generation Capacity Resource for which a Capacity Market Seller has not timely submitted the certifications required under Tariff, Attachment DD, section 5.14(h-2)(1) shall be subject to the provisions of the Minimum Offer Price Rule. Notwithstanding the foregoing, if a Capacity Market Seller submits a timely unit-specific exception pursuant to Tariff, Attachment DD, section 5.14(h-2)(4) for the relevant Delivery Year, and PJM approves the unit-specific MOPR Floor Offer Price, then the Capacity Market Seller may use such floor price regardless of whether it timely submitted the foregoing certifications.

(3) **Minimum Offer Price Rule.** Any Sell Offer for a Generation Capacity Resource that is subject to the provisions of the Minimum Offer Price Rule pursuant to Tariff, Attachment DD, section 5.14(h-2)(2) shall have an offer price no lower than the applicable MOPR Floor Offer Price, unless the applicable MOPR Floor Offer Price is higher than the

applicable Market Seller Offer Cap, in which circumstance the Capacity Market Seller, to participate in an RPM Auction, must request a unit-specific value determined in accordance with the unit-specific MOPR Floor Offer Price process, and the unit-specific MOPR Floor Offer Price shall establish the offer level for such resource.

(A) New Entry MOPR Floor Offer Price. For a Generation Capacity Resource that is subject to the provisions of the Minimum Offer Price Rule pursuant to Tariff, Attachment DD, section 5.14(h-2)(2) and for which a Sell Offer based on that resource, or any uprate of such Generation Capacity Resource participating in the generation interconnection process under Tariff, Part IV, Subpart A, that has not cleared an RPM Auction for any Delivery Year, the applicable MOPR Floor Offer Price, based on the net cost of new entry for the resource type, shall be, at the election of the Capacity Market Seller, (i) the unit-specific value determined in accordance with the unit-specific MOPR Floor Offer Price process in Tariff, Attachment DD, section 5.14(h-2)(4) 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 or 2026/2027 Delivery Year, as applicable, net of estimated net energy and ancillary service revenues for the resource type and Zone in which the resource is located.

Resource Type	**Through the 2025/2026 Delivery Years: Gross Cost of New Entry (2022/2023 $/ MW-day) (Nameplate)**	**For the 2026/2027 Delivery Year and Subsequent Delivery Years: Gross Cost of New Entry (2026/2027 $/ MW-day) (Nameplate)**
Nuclear	$2,000	$2,568
Coal	$1,068	$1,480
Combined Cycle	$320	$540
Combustion Turbine	$294	$427
Fixed Solar PV	$271	$298
Tracking Solar PV	$290	$321
Onshore Wind	$420	$438
Offshore Wind	$1,155	$1,351
Battery Energy Storage	$532	$502

The gross cost of new entry values in the table above are expressed in dollars per MW-day in terms of nameplate megawatts. For purposes of submitting a Sell Offer, the gross cost of new entry values must be converted to a net cost of new entry by subtracting the estimated net energy and ancillary service revenues, as determined below, from the gross cost of new entry. However, the resultant net cost of new entry of the battery energy storage resource type in the table above must be multiplied by 2.5. The net cost of new entry based on nameplate capacity is then converted to Unforced Capacity ("UCAP") MW-day. For the 2023/2024 Delivery Year and subsequent Delivery Years, to determine the applicable UCAP MW-day value, the net cost of new entry is adjusted as follows: for battery storage, wind, and solar resource types, the applicable ELCC Class Rating; or for all other generation resource types, the applicable class average EFORd. The resulting default New Entry MOPR Floor Offer price in UCAP/MW-day terms shall be applied to each MW offered for the Capacity Resource regardless of the actual Sell Offer quantity and regardless of whether the Sell Offer is for a Seasonal Capacity Performance Resource.

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 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, 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. Through the 2024/2025 Delivery Years, 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, plus reactive 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; and

(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.

For the 2025/2026 Delivery Year and subsequent Delivery Years, the net energy and ancillary services revenue shall be the average of the net energy and ancillary services revenues that the resource is projected to receive from the PJM energy and ancillary service markets for the applicable Delivery Year from three separate simulations, with each such simulation using forward prices shaped using historical data from one of each of the three consecutive calendar years preceding the time of the determination for the RPM Auction to take account of year-to-year variability in such hourly shapes. Each net energy and ancillary services revenue simulation shall be conducted in accordance with the following and the PJM Manuals:

(ix) for nuclear resource type, the net energy and ancillary services revenue estimate for each Zone shall be determined by the gross energy market revenue determined by the product of [average annual day-ahead Forward Hourly LMPs for such Zone, 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 for the 2025/2026 Delivery Year, or starting with the 2026/2027 Delivery Year and subsequent Delivery Years, $7.99/MWh for a single unit plant or $7.74/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 reactive services revenue of $2,251/MW-year;

(x) for coal resource type, the net energy and ancillary services revenue estimate for each Zone shall be determined by the Projected EAS 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 for the 2025/2026 Delivery Year, or starting with the 2026/2027 Delivery Year and subsequent Delivery Years, $10.92/MWh) using day-ahead and real-time Forward Hourly LMPs for such Zone and Forward Hourly Ancillary Service Prices, and daily forecasted coal prices, as set forth in the PJM Manuals, plus reactive services revenue of $2,217/MW-year;

(xi) for the 2025/2026 Delivery Year, for combustion turbine resource type, the net energy and ancillary services revenue estimate for each Zone shall be determined by the Projected EAS Dispatch of a single General Electric Frame 7HA turbine with evaporating cooling, Selective Catalytic Reduction technology, with dual Fuel capability, with the heat rate assumed for the combustion turbine resource shall be 9,134 BTU/kWh, the variable operations and maintenance expenses for such resources, inclusive of Maintenance Adder costs, shall be $6.93/MWh, plus ancillary services revenue of $2,199/MW-year. Starting with the 2026/2027 Delivery Year and subsequent Delivery Years, for combustion turbine resource type, the net energy and ancillary services revenue estimate for each Zone shall be determined by the Projected EAS Dispatch of a single General Electric Frame 7HA.02 turbine with evaporating cooling, Selective Catalytic Reduction technology, with the heat rate assumed for the combustion turbine resource shall be 9,189 BTU/kWh, the variable operations and maintenance expenses for such resources, inclusive of Maintenance Adder costs, shall be $1.19/MWh, plus ancillary services revenue of $3,565/MW-year.

(xii) for combined cycle resource type, for the 2025/2026 Delivery Year, the net energy and ancillary services revenue estimate for each Zone 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 6,501 BTU/kwh, the variable operations and maintenance expenses for such resource, inclusive of Maintenance Adder costs, shall be $2.11/MWh, plus reactive services revenue of $3,350/MW-year. Starting with the 2026/2027 Delivery Year and subsequent Delivery Years, for combined cycle resource type, the net energy and ancillary services revenue estimate for each Zone shall be determined in a manner consistent with the methodology described in Tariff, Attachment DD, section 5.10(a)(v-1)(B) for the Reference Resource combined cycle.

(xiii) for solar PV resource type, the net energy and ancillary services revenue estimate for each Zone 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 Forward Hourly LMP for such Zone and applicable to such hour with this product summed across all of the hours of an annual period, plus reactive services revenue of $6,791/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;

(xiv) for onshore wind resource type, the net energy and ancillary services revenue estimate for each Zone 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 Forward Hourly LMP for such Zone applicable to such hour with this product summed across all of the hours of an annual period, plus reactive services revenue of $4,027/MW-year;

(xv) for offshore wind resource type, the net energy and ancillary services revenue estimate for each Zone shall be determined by the gross energy market revenue equal to the product of [the average annual real-time Forward Hourly LMP for such Zone times 8,760 hours times an assumed annual capacity factor of 45%], plus reactive services revenue of $4,027/MW-year;

(xvi) for Capacity Storage Resource, the net energy and ancillary services revenue estimate shall be estimated by the Projected EAS Dispatch of a 1 MW, 4MWh resource, with an 85% roundtrip efficiency, and assumed to be dispatched between 95% and 5% state of charge against day-ahead and real-time Forward Hourly LMPs for such Zone and Forward Hourly Ancillary Service Prices, plus reactive services revenue of $3,903/MW-year.

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. 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 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.

Any Generation Capacity Resource that is subject to the provisions of the Minimum Offer Price Rule pursuant to Tariff, Attachment DD, section 5.14(h-2)(2) and that has not previously cleared an RPM Auction for that or any prior Delivery Year and for which there is no default MOPR Floor Offer Price provided in accordance with this section, including hybrid resources, must seek a unit-specific value determined in accordance with the unit-specific MOPR Floor Offer Price process below to participate in an RPM Auction. Failure to obtain a unit-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.

(i) For a Generation Capacity Resource that is subject to the provisions of the Minimum Offer Price Rule pursuant to Tariff, Attachment DD, section 5.14(h-2)(2) and for which a Sell Offer based on that resource has previously cleared an RPM Auction for any Delivery Year, the applicable Cleared MOPR Floor Offer Price shall be, at the election of the Capacity Market Seller, (a) based on the unit-specific MOPR Floor Offer Price, as determined in accordance with Tariff, Attachment DD, section 5.14(h-2)(4) below, or (b) 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 or 2026/2027 Delivery Year, as applicable, to reflect changes in avoidable costs, net of projected PJM market revenues equal to, through the 2024/2025 Delivery Year, the resource's historical net energy and ancillary service revenues consistent with Tariff, Attachment DD, section 6.8(d), or starting with the 2025/2026 Delivery Year and subsequent Delivery Years, the resource's net energy and ancillary service revenues for the resource type, as determined in accordance with subsection (ii) below.

Existing Resource Type	**Through the 2025/2026 Delivery Years: Default Gross ACR (2022/2023) ($/MW-day) (Nameplate)**	**For the 2026/2027 Delivery Year and Subsequent Delivery Years: Default Gross ACR (2026/2027) ($/ MW-day) Nameplate**
Nuclear - single	$697	$591
Nuclear - dual	$445	$537
Coal	$80	$94
Combined Cycle	$56	$113

Combustion Turbine	$50	$52
Steam Oil & Gas	NA	$64
Solar PV (fixed and tracking)	$40	$70
Wind Onshore	$83	$147

The default gross Avoidable Cost Rate values in the table above are expressed in dollars per MW-day in terms of nameplate megawatts. For purposes of submitting a Sell Offer, the default Avoidable Cost Rate values must be net of estimated net energy and ancillary service revenues, and then the difference is ultimately converted to Unforced Capacity ("UCAP") MW-day, where the UCAP MW-day value will be determined based on the 2023/2024 Delivery Year and subsequent Delivery Years, the resource-specific Accredited UCAP value for solar and wind resource types (with appropriate time-weighting for any winter Capacity Interconnection Rights) or the resource-specific EFORd for all other generation resource types and on. The resulting default Cleared MOPR Floor Offer price in UCAP/MW-day terms shall be applied to each MW offered for the Capacity Resource regardless of actual Sell Offer quantity and regardless of whether the Sell Offer is for a Seasonal Capacity Performance Resource.

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. Updated estimates of the net energy and ancillary service revenues shall be determined on a resource-specific basis in accordance with Tariff, Attachment DD, section 6.8(d) 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 Resource that is subject to the provisions of the Minimum Offer Price Rule pursuant to Tariff, Attachment DD, section 5.14(h-2)(2) that have cleared in an RPM Auction for any 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.

Any Generation Capacity Resource that is subject to the provisions of the Minimum Offer Price Rule pursuant to Tariff, Attachment DD, section 5.14(h-2)(2) and that has previously cleared an RPM Auction for any Delivery Year and for which there is no default MOPR Floor Offer Price provided in accordance with this section, including hybrid resources, must seek a unit-specific value determined in accordance with the unit-specific MOPR Floor Offer Price process below to participate in an RPM Auction. Failure to obtain a unit-specific MOPR Floor Offer Price will result in the Office of the Interconnection rejecting any Sell Offer based on such resource.

(ii) Effective with the 2025/2026 Delivery Year and subsequent Delivery Years, the net energy and ancillary services revenue is equal to forecasted net revenues which shall be determined in accordance with the applicable resource type net energy and ancillary services revenue determination methodology set forth in Tariff, Attachment DD, section 5.14(h-2)(2)(A)(ix) through (xvi) and using the subject resource's operating parameters as determined in accordance with the PJM Manuals based on (a) offers submitted in the Day-ahead Energy Market and Real-time Energy Market over the calendar year preceding the time of the determination for the RPM Auction; (b) the resource-specific operating parameters approved, as applicable, in accordance with Operating Agreement, Schedule 1, section 6.6(b) and Operating Agreement, Schedule 2 (including any Fuel Costs, emissions costs, Maintenance Adders, and Operating Costs); (c) the resource's Accredited UCAP Factor; (d) Forward Hourly LMPs at the generation bus as determined in accordance with Tariff, Attachment DD, section 5.10(a)(v-1)(C)(6); and (e) the resource's stated annual revenue requirement for reactive services; plus any unit-specific bilateral contract. In addition, the following resource type-specific parameters shall be considered; (f) for combustion turbine, combined cycle, and coal resource types: the installed capacity rating, ramp rate (which shall be equal to the maximum ramp rate included in the resource's energy offers over the most recent previous calendar year preceding the determination for the RPM Auction), and the heat rate as determined as the resource's average heat rate at full load as submitted to the Market Monitoring Unit and the Office of the Interconnection, where for combined cycle resources heat rates will be determined at base load and at peak load (e.g., without duct burners and with duct burners), as applicable; (g) for nuclear resource type: anticipated refueling schedule; (h) for solar and wind resource types: the resource's output profiles for the most recent three calendar years, as available; and (i) for battery storage resource type: the nameplate capacity rating (on a MW / MWh basis).

To the extent the resource has not achieved commercial operation, the operating parameters used in the simulation of the net energy and ancillary service revenues will be based on the manufacturer's specifications and/or from parameters used for other existing, comparable resources, as developed by the Market Monitoring Unit and the Capacity Market Seller, and accepted by the Office of the Interconnection.

A Capacity Market Seller intending to submit a Sell Offer in any RPM Auction for a Cleared Capacity Resource with State Subsidy based on a net energy and ancillary services revenue determination that does not use the foregoing methodology or parameter inputs stated for that resource type shall, at its election, submit a request for a resource-specific MOPR Floor Offer Price for such Capacity Resource pursuant to Tariff, Attachment DD, section 5.14(h-2)(3) below

(4) **Unit-Specific Exception**. A Capacity Market Seller intending to submit a Sell Offer in any RPM Auction for a Generation Capacity Resource that is subject to the provisions of the Minimum Offer Price Rule below the applicable default MOPR Floor Offer Price may, at its election, submit a request for a unit-specific exception for such Capacity Resource. A Capacity Market Seller intending to submit a Sell Offer in any RPM Auction for a Generation Capacity Resource that is under a fact-specific review for Buyer-Side Market Power pursuant to Tariff, Attachment DD, section 5.14(h-2)(2)(B)(ii), and where the offer is below the

applicable default MOPR Floor Offer Price may, at its election, submit a request for a unit-specific exception for such Generation Capacity Resource. A Sell Offer below the default MOPR Floor Offer Price, but no lower than the unit-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. The unit-specific MOPR Floor Offer Price determined under this provision shall be based on the unit-specific Accredited UCAP value for battery energy storage resource types and for solar and wind generation resource types (appropriately time-weighted for any winter Capacity Interconnection Rights) or on the unit-specific EFORd for all other generation resource types, and shall be applied to each MW offered by the resource regardless of actual Sell Offer quantity and regardless of whether the Sell Offer is for a Seasonal Capacity Performance Resource. Such Sell Offer is permissible because it is consistent with the competitive, cost-based, fixed, net cost of the resource. 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 unit-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)(3)(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 unit-specific exception for a Generation Capacity Resource that is subject to the provisions of the Minimum Offer Price Rule pursuant to Tariff, Attachment DD, section 5.14(h-2)(2) and that has never cleared an RPM Auction, 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 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 or any other revenues outside of PJM markets that do not constitute Conditioned State Support), 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 unit-specific exception hereunder. The request also shall identify all revenue sources (exclusive of any Conditioned State Support or bilateral contracts that direct submission of an offer to lower RPM Auction clearing prices) relied upon in the Sell Offer to offset the claimed fixed costs, including, without limitation, long-term power supply contracts, tolling agreements, evidence of compensation outside the PJM market not tied to Conditioned State Support or a bilateral contract that directs submission of an offer to lower RPM Auction clearing prices, 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. Through the 2024/2025 Delivery Year, 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, which may include Maintenance Adders, 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. Starting with the 2025/2026 Delivery Year and subsequent Delivery Years, in making such demonstration, the Capacity Market Seller may rely upon revenues projected by well-defined, forward-looking dispatch models designed to generally follow the rules and processes of PJM's energy and ancillary services market. Such models must utilize publicly available forward prices for electricity and fuel in the PJM Region. Any modifications made to the forward electricity and fuel prices must similarly use publicly available data. Alternative forward prices for fuel may be used if accompanied by contractual evidence showing the applicability of the alternative fuel price. Where forward fuel markets are not available, publicly available estimates of future fuel prices may be used. The model shall also contain estimates of, variable operation and maintenance expenses, which may include Maintenance Adders, and emissions allowance prices. Documentation for net revenues also must 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, capacity factors, 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 the alternative, the Capacity Market Seller may request that the Market Monitoring Unit, subject to acceptance by the Office of Interconnection, produce a resource-specific Energy & Ancillary Services Offset value for such resource using the Forward Hourly LMPs, Forward Hourly Ancillary Service Prices and either Forward Daily Natural Gas Prices for combustion turbines and combined cycle resources, or forecasted fuel prices for other resource types, plus plant parameters and capability information specific to the dispatch of the resource, as outlined above. 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.

(C) Through the 2024/2025 Delivery Years, for a Unit-Specific Exception for a Generation Capacity Resource that is subject to the provisions of the Minimum Offer Price Rule pursuant to Tariff, Attachment DD, section 5.14(h-2)(2) and that has previously cleared an RPM Auction, 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 Conditioned State Support or bilateral contracts that direct submission of an offer to lower RPM Auction clearing prices) relied upon in the Sell Offer to offset the claimed fixed costs, including, without limitation, long-term power supply contracts, tolling agreements, evidence of compensation outside of PJM markets not tied to Conditioned State Support or a bilateral contract that directs submission of an offer to lower RPM Auction clearing prices, 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, which may include Maintenance Adders, and 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.

(C-1) Beginning with the 2025/2026 Delivery Year and subsequent Delivery Years, for a Unit-Specific Exception for a Generation Capacity Resource that is subject to the provisions of the Minimum Offer Price Rule pursuant to Tariff, Attachment DD, section 5.14(h-2)(2) and that has previously cleared an RPM Auction, 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 shall, 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 Conditioned State Support or bilateral contracts that direct submission of an offer to lower RPM Auction clearing prices) relied upon in the Sell Offer to offset the claimed fixed costs, including, without limitation, long-term power supply contracts, tolling agreements, evidence of compensation outside of PJM markets not tied to Conditioned State Support or a bilateral contract that directs submission of an offer to lower RPM Auction clearing prices, 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 revenues projected by well-defined, forward-looking dispatch models designed to generally follow the rules and processes of PJM’s energy and ancillary services market. Such models must utilize publicly available forward prices for electricity and fuel in the PJM Region. Any modifications made to the forward electricity and fuel prices must similarly use publicly available data. Alternative forward prices for fuel may be used if accompanied by contractual evidence showing the applicability of the alternative fuel price. Where forward fuel markets are not available, publicly available estimates of future fuel sources may be used. The model shall also contain estimates of variable operation and maintenance expenses, which may include Maintenance Adders, and emissions allowance prices. Documentation for net revenues also must 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, capacity factors, 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.

In the alternative, the Capacity Market Seller may request that the Market Monitoring Unit, subject to acceptance by the Office of Interconnection, produce a resource-specific projected energy and ancillary services markets revenues for such resource using the Forward Hourly LMPs, Forward Hourly Ancillary Service Prices and either Forward Daily Natural Gas Prices for combustion turbines and combined cycle resources, or forecasted fuel prices for other resource types, plus plant parameters and capability information specific to the dispatch of the resource, as outlined above. 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.

(D) A Sell Offer evaluated at the unit-specific exception shall be permitted if the information provided reasonably demonstrates that the Sell Offer's competitive, fixed, cost-based offer level 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, and that out-of-market compensation is not tied to Conditioned State Support or a bilateral contract that directs submission of an offer to lower RPM Auction clearing prices. Failure to adequately support such claimed cost advantages or revenues so as to enable the Office of the Interconnection to make the determination required in this section will result in the elimination of consideration of the unsupported element(s) of a unit-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 unit-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 unit-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 unit-specific determination unless and until ordered to do otherwise by FERC.

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) above also shall receive a credit, comparable to the Capacity Transfer Rights provided to Load-Serving Entities under Tariff, Attachment DD, section 5.15. Such credit shall be equal to the locational capacity price difference specified in section 5.14(i)(1) above 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.

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. A Capacity Market Seller offering above $0/MW-day must support and obtain approval of a unit-specific Market Seller Offer Cap pursuant to the procedures and standards of subsection (b) of this section 6.4 or may, at its election, if available, utilize a Market Seller Offer Cap determined using the applicable default gross Avoidable Cost Rate for the applicable resource type shown in the table below, as adjusted for Delivery Years subsequent to the 2022/2023 or 2026/2027 Delivery Year, as applicable, to reflect changes in avoidable costs, net of *Projected* PJM *Market Revenues* equal to the resource's net energy and ancillary service revenues for the resource type, as determined in accordance with Tariff, Attachment DD, section 6.8(d).

Existing Resource Type	Through the 2025/2026 Delivery Years: Default Gross ACR (2022/2023) ($/MW-day) (Nameplate)	For the 2026/2027 Delivery Year and Subsequent Delivery Years: Default Gross ACR (2026/2027) ($/MW-day) (Nameplate)
Nuclear – single	$697	$591
Nuclear – dual	$445	$537
Coal	$80	$94
Combined Cycle	$56	$113
Combustion Turbine	$50	$52
Steam Oil & Gas	NA	$64
Solar PV (fixed and tracking)	$40	$70
Wind Onshore	$83	$147

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.

(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, or calculate an alternative unit-specific Market Seller Offer Cap based on the submitted documentation, 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. In the event the Office of the Interconnection rejects the Capacity Market Seller's requested unit-specific Market Seller Offer Cap for a particular Existing Generation Capacity Resource, the Capacity Market Seller of such Capacity Resource may submit an offer up to (1) should one exist, the default gross Avoidable Cost Rate for the applicable resource type net of *Projected* PJM *Market Revenues* equal to the resource's net energy and ancillary service revenues for the resource type, or (2) the unit-specific Market Seller Offer Cap proposed by the Market Monitoring Unit upon PJM approval of such value, or (3) an alternative unit-specific Market Seller Offer Cap calculated by the Office of the Interconnection based on the submitted documentation. 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 6.4(a) above.

Notwithstanding the provisions of Tariff, Attachment M-Appendix, section II.E.2 and this Tariff, Attachment DD, section 6.4(b), no later than eighty (80) days prior to the commencement of the offer period for the auction, the Market Monitoring Unit and the relevant Capacity Market Seller may mutually agree on the value of such Market Seller Offer Cap. Nothing herein shall preclude the Market Monitoring Unit from modifying the Market Seller Offer Cap for a Generation Capacity Resource beyond the eighty-day (80-day) deadline prior to the commencement of the offer period for the auction, through the commencement of the offer period for the auction, so long as the Market Monitoring Unit and the relevant Capacity Market Seller mutually agree with the value of such Market Seller Offer Cap. The Capacity Market Seller shall notify the Market Monitoring Unit in writing, with a copy to the Office of the Interconnection, if such an agreement with the Market Monitoring Unit has been reached. The Office of the Interconnection shall review the Market Seller Offer Cap submitted by the Capacity Market Seller and make a determination whether the Market Seller Offer Cap complies with the tariff, and notify the Capacity Market Seller and the Market Monitoring Unit of its determination.

(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 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 1.1 times the Capacity Resource Clearing Price in the Base Residual Auction for the relevant LDA and Delivery Year.

(e) Effective with the 2025/2026 Delivery Year, Capacity Market Sellers that submit a unit-specific Market Seller Offer Cap by the deadline may request to use and provide support for a segmented offer cap to reflect incremental costs of having a capacity obligation across different segments of their unit. Such request must provide adequate justification for the use of a segmented offer cap with supporting documentation and calculations for the Market Seller Offer Cap of each segment. Segmented Market Seller Offer Caps shall be comprised of multiple Market Seller Offer Caps, each calculated in accordance with Tariff, Attachment DD, section 6.8. If elected by the Capacity Market Seller, the first segment may have a Market Seller Offer Cap reflective of incremental expenses directly required to operate a Generation Capacity Resource that a Generation Owner would not incur if such generating unit were to mothball or retire, in accordance with Tariff, Attachment DD, section 6.8(b). All other offer segments (and, if elected by the Capacity Market Seller, the first segment) shall reflect incremental costs that would be avoided only in the absence of a capacity obligation, in accordance with Tariff, Attachment DD, section 6.8(b).

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 $0/MW-day, except as described in Tariff, Attachment DD, section 6.4(a); 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 Market Seller Offer Cap.

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: 1) the default Net CONE value for the applicable technology, as calculated in accordance with Tariff, Attachment DD, section 5.14(h-2)(A), for such Delivery Year in the Zone for which such Sell Offer was submitted; or 2) if there is no default Net CONE value for the applicable technology for such Delivery Year in the Zone, the Net CONE that is used in setting the VRR Curve applicable for such Delivery Year in the LDA for which such Sell Offer was submitted. Notwithstanding the above, the Sell Offer of a Planned Generation Capacity Resource shall not be rejected if offered at or below a unit-specific offer price that is calculated in accordance with Tariff, Attachment DD, section 5.14(h-2)(4)(B), and submitted and approved in accordance with Tariff, Attachment DD, section 6.4(b). 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.

6.7 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 above $0/MW-day, except as 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, if applicable, 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.

(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 in Tariff, Attachment DD, section 6.8 and applied to the unit’s Base Offer Segment. For determining the costs that are avoidable in the unit-specific Avoidable Cost Rate, Capacity Market Sellers shall indicate if the resource will mothball or retire if not cleared in the capacity market, or if the resource shall continue operating and participate in the energy and ancillary services markets during the Delivery Year if not cleared. Capacity Market Sellers that indicate a decision to mothball or retire the resource if not cleared, and use that as the basis for the unit’s avoidable costs, shall be required to provide an officer certification. Should the resource not clear in the capacity market and there is a change in the decision to mothball or retire the resource, the Office of the Interconnection and/or the Market Monitoring Unit may require the Capacity Market Seller to provide support for such change.

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, retaining, or

otherwise managing the risks of Non-Performance Charges associated with submission of a Capacity Performance Resource offer such as insurance quotes or expected 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. CPQR shall also be considered reasonably supported if a Capacity Market Seller provides supporting documentation, along with an officer certification, that their risk model, inputs, and costs of CPQR have undergone a review by an independent third party entity with experience in evaluating capacity performance insurance policies to confirm that the proposed valuation of risk is consistent with actuarial practices in the industry. 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.

Notwithstanding the above, a CPQR shall be considered reasonably supported when calculated based on the following formula: Risk Cost multiplied by Extreme Value, where:

- Risk Cost reflects an estimated cost of managing the risks of Non-Performance Charges, and by default, shall equal the after tax Weighted Average Cost of Capital (calculated as: percent equity * cost of equity + percent debt * debt interest rate * (1- effective tax rate)), which shall be determined in a manner consistent with the calculated value used in the CRF formula in the APIR component. A Capacity Market Seller that submits a unit-specific Market Seller Offer Cap may substitute their own estimate of Risk Cost with supporting documentation.

- Extreme Value is the annual total net Non-Performance Charges for the resource at a pre-determined confidence interval (i.e. 95th percentile), based on a probabilistic analysis conducted by the Office of the Interconnection that models the resource's performance under a range of simulated system conditions to measure the distribution of potential annual total net over- and under-performance of the resource, along with the annual total net non-performance charges and bonus credits during the simulated Performance Assessment Intervals in the analysis.

- **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, applied in accordance with the terms specified below. CRF values are calculated for recovery periods of 4, 5, 10, 15, 20, 25, and 30 years, using the following formula with assumptions of the following components: (i) capital structure and cost of capital; (ii) debt interest rate; (iii) state income tax rate, and (iv) federal income tax and depreciation rates as utilized by the U.S. Internal Revenue Service.

$$\mathrm{CRF} = \frac{r(1+r)^N\left[1 - \frac{sB}{\sqrt{1+r}} - s(1-B)\sqrt{1+r}\sum_{j=1}^{L}\frac{m_j}{(1+r)^j}\right]}{(1-s)\sqrt{1+r}\,[(1+r)^N - 1]}$$

Where:
r is the after tax Weighted Average Cost of Capital (calculated as: percent equity * cost of equity + percent debt * debt interest rate * (1- effective tax rate))
s is the effective tax rate (calculated as: State Tax Rate + Federal Tax Rate*(1-State Tax Rate))
B is the bonus depreciation percent
N is the cost recovery period (years)
L is the lessor of N or 16 (years)
m_j is the modified accelerated cost recovery system (MACRS) depreciation factor for year j =1, . . ., 16.

The CRF values of the following table shall be used for RPM Auctions through and including the Base Residual Auction conducted for 2022/2023 Delivery Year. Thereafter, the table of CRF values applicable to each RPM Auction shall be determined and posted on the PJM website by no later than 150 days prior to the commencement of the offer period of the RPM Auction. The values of the posted CRF table shall be determined using federal income tax laws in effect at the time of the determination for the relevant Delivery Year and shall use the same assumptions of (i) capital structure and cost of capital; (ii) debt interest rate; and (iii) state income tax rate, as those utilized to calculate the Cost of New Entry for the Reference Resource for the relevant Delivery Year. For the purpose of the CRF determination, the state income tax rate will be set equal to the average state income tax rate used to calculate the Cost of New Entry of the Reference Resource across the four CONE Regions. The CRF for the 40 Plus Alternative option shall be set equal to 1.1 and is not calculated by the formula above.

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 or posted 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 or posted 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 were to mothball or retire and did not operate or have a capacity obligation in the Delivery Year. Alternatively, for Capacity Market Sellers that have indicated in their submission of a unit-specific Market Seller Offer Cap that the resource will continue to operate and participate in the energy and ancillary services markets during the Delivery Year if not cleared in the capacity market, avoidable costs and expenses shall be limited to the incremental costs that would be avoided only in the absence of a capacity obligation such as CPQR. Such Capacity Market Sellers of resources that will continue to operate and participate in the energy and ancillary services markets shall not include labor, maintenance, and other operating expenses that would be avoided only if the Capacity Resource were not operating and participating in the energy and ancillary services markets 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) For Delivery Years up to and including the 2024/2025 Delivery Year, 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 Agreement 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.

(d-1) Effective with the 2025/2026 and subsequent Delivery Years, Projected PJM Market Revenues for any Generation Capacity Resource to which the Avoidable Cost Rate is applied shall be equal to forecasted net revenues, which shall be determined in accordance with Tariff, Attachment DD, section 5.14(h-2)(2)(B)(ii), or for resource types not specified in such section, in a manner consistent with the methodologies described in such section, that utilizes Forward Hourly LMPs and Forward Hourly Ancillary Service Prices for such resource, forecasted fuel prices as applicable, as well as resource-specific operating parameters and capability information specific to the simulated dispatch of such resource, where such dispatch shall either consider the hourly output profiles for Intermittent Resources in a manner consistent with solar and onshore wind methodologies, or utilize the Projected EAS Dispatch. To the extent the resource has achieved commercial operation, the dispatch shall utilize the resource-specific operating parameters as determined in accordance with the PJM Manuals based on offers submitted in the Day-ahead Energy Market and Real-time Energy Market, as well as the operating parameters approved, as applicable, in accordance with Operating Agreement, Schedule 1, section 6.6(b) and Operating Agreement, Schedule 2 (including any Fuel Costs, emissions costs, Maintenance Adders, and Operating Costs). Adjustments to resource-specific operating parameters may be submitted to the Market Monitoring Unit and the Office of the Interconnection for review and consideration in the simulated dispatch with supporting documentation. For resources that have not yet achieved commercial operation, the operating parameters used in the simulation of the net energy and ancillary service revenues will be based on the manufacturer's specifications and/or from parameters used for other existing, comparable resources, as developed by the Market Monitoring Unit and the Capacity Market Seller, and accepted by the Office of the Interconnection.

In the alternative, the Capacity Market Seller may provide their own estimate of Projected PJM Market Revenues to the Market Monitoring Unit and the Office of the Interconnection for review and approval. Such a request shall identify all revenue sources (exclusive of any State Subsidies), 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 standards prescribed above. In making such demonstration, the Capacity Market Seller may rely upon revenues projected by well-defined, forward-looking dispatch models designed to generally follow the rules and processes of PJM's energy and ancillary services markets. Such models must utilize forward prices for energy, ancillary service and fuel in the PJM Region based on contractual evidence of an alternative fuel price or sourced from liquid forward markets (where available), and other publicly available data to develop the forward prices used in the estimate. Where forward fuel markets are not available, publicly available estimates of future fuel sources may be used. The model shall also contain estimates of variable operation and maintenance expenses, which may include Maintenance Adders, and emissions allowance prices. Documentation for net revenues also must 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, capacity factors, 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.

Notwithstanding the foregoing, in the case that the Capacity Market Seller has indicated in their submission of a unit-specific Market Seller Offer Cap that the resource will continue to operate and participate in the energy and ancillary services markets during the Delivery Year if not cleared in the capacity market, the Projected PJM Market Revenues shall be zero dollars.

10A. CHARGES FOR NON-PERFORMANCE AND CREDITS FOR PERFORMANCE

(a) Each Capacity Market Seller that commits a Capacity Resource for a Delivery Year (whether through an RPM Auction, a bilateral transaction, or as Locational UCAP), each Locational UCAP Seller that sells Locational UCAP from a Capacity Resource for a Delivery Year, each PRD Provider that commits Price Responsive Demand for a Delivery Year, shall be charged to the extent the performance of each of its committed Capacity Resources or Price Responsive Demand during all or any part of a clock-hour when an Emergency Action is in effect falls short of the expected performance of such resources (as determined herein) and the revenue from such charges shall be provided to Market Participants with generation, demand response resources, or Price Responsive Demand that perform during such hour in excess of the level expected based on commitments (if any) of such resources; provided, however, for the 2025/2026 Delivery Year and subsequent Delivery Years, the revenue from such charges shall be provided to Market Participants with committed Generation Capacity Resources in accordance with this Tariff, Attachment DD, section 10A(g).

(b) Performance shall be measured for purposes of this assessment during each Performance Assessment Interval.

(c) For each Performance Assessment Interval, the Office of the Interconnection shall determine whether, and the extent to which, the actual performance of each Capacity Resource, Locational UCAP, and Price Responsive Demand has fallen short of the performance expected of such committed Capacity Resource or Price Responsive Demand, and the magnitude of any such shortfall, based on the following formula, and as further detailed in the PJM Manuals:

Performance Shortfall = Expected Performance - Actual Performance

Where the result of such formula is a positive number and where:
Expected Performance =

for Generation Capacity Resources (including external Generation Capacity Resources for any Performance Assessment Interval for which performance by such external resource would have helped resolve a declared Emergency Action); and Capacity Storage Resources: [(Resource Committed Capacity * the Balancing Ratio)];

where

Resource Committed Capacity = the total megawatts of Unforced Capacity of the Capacity Resource committed by such Capacity Market Seller or Locational UCAP Seller; and

The Balancing Ratio = (All Actual Generation Performance, Storage Resource Performance, Net Energy Imports, Price Responsive Demand Bonus Performance, and Demand Response Bonus Performance) / (All Committed Generation and Storage Capacity); provided, however, that Net Energy Imports shall be included in the calculation of the Balancing Ratio only for any

Performance Assessment Interval for which performance by any external Generation Capacity Resource would have helped resolve the Emergency Action that was the subject to the Performance Assessment Interval; and provided further that effective with the 2025/2026 Delivery Year and subsequent Delivery Years, the Balancing Ratio shall solely include the actual performance of committed Generation Capacity and Storage Resources, and shall exclude the megawatts of committed Generation and Storage Capacity Resources that are not considered in the calculation of a Performance Shortfall for a Performance Assessment Interval pursuant to subsection (d-1) below; and provided further that the Balancing Ratio shall not exceed a value of 1.0.

for purposes of which

All Committed Generation and Storage Capacity = the total megawatts of Unforced Capacity of all Generation Capacity Resources (including external Generation Capacity Resources for any Performance Assessment Interval for which performance by such external resource would have helped resolve the declared Emergency Action that was the subject to the Performance Assessment Interval); and all Capacity Storage Resources committed by all Capacity Market Sellers, FRR Entities, Locational UCAP Sellers;

All Actual Generation Performance and Storage Resource Performance = through the 2024/2025 Delivery Year, the total amount of Actual Performance for all generation resources (including external Generation Capacity Resources for any Performance Assessment Interval for which performance by such external resource would have helped resolve the declared Emergency Action that was the subject to the Performance Assessment Interval; provided, however, that for the 2025/2026 Delivery Year and subsequent Delivery Years, the Actual Performance shall be limited to resources who hold a capacity commitment during the Performance Assessment Interval;

Net Energy Imports = through the 2024/2025 Delivery Year, the sum of interchange transactions importing energy into PJM (not including those associated with external Generation Capacity Resources and therefore included in All Actual Generation Performance) minus the sum of interchange transactions exporting energy out of PJM, but not less than zero. Beginning with the 2025/2026 Delivery Year, Net Energy Imports shall be zero;

Demand Response Bonus Performance = through the 2024/2025 Delivery Year, the sum of Bonus performance provided by Demand Response resources as calculated in (g) below. Beginning with the 2025/2026 Delivery Year, Demand Response Bonus Performance shall be zero;

Price Responsive Demand Bonus Performance = through the 2024/2025 Delivery Year, the sum of Bonus performance provided by Price Responsive Demand as calculated in (g) below. Beginning with the 2025/2026 Delivery Year, Price

Responsive Demand Bonus Performance shall be zero;

and for Demand Resources, Energy Efficiency Resources, and Qualifying Transmission Upgrades: Resource Committed Capacity;

where

Resource Committed Capacity = the total megawatts of capacity committed from such Capacity Resource committed capacity without making any adjustment for the Forecast Pool Requirement, and beginning with the 2025/2026 Delivery Year, for Demand Resources, without making an adjustment for the applicable ELCC Class Rating;

and for PRD Provider: Price Responsive Demand Committed

where

Price Responsive Demand Committed = the Nominal PRD Value committed by the PRD Provider in the area defined by the Performance Assessment Interval, adjusted to account for any PRD registrations in such area that were not subject to compliance measurement.

and

Actual Performance =

for each generation resource, the metered output of energy delivered to PJM by such resource and adjusted by the resource's real-time reserve or regulation assignment, if any, during the Performance Assessment Interval; provided, however, for the 2025/2026 Delivery Year and subsequent Delivery Years, Actual Performance shall not exceed the installed capacity commitment for the resource.

for each storage resource, the metered output of energy delivered to PJM by such resource and adjusted by the resource's real-time reserve or regulation assignment, if any, during the Performance Assessment Interval; provided, however, for the 2025/2026 Delivery Year and subsequent Delivery Years, Actual Performance shall not exceed the installed capacity commitment for the resource.

for each Demand Resource, the demand response provided to PJM by such resource, and adjusted by such resource's real-time reserve or regulation assignment, if any, during the Performance Assessment Interval, as established through the PJM demand response settlement procedure consistent with the standards specified in RAA, Schedule 6; provided, however, for the 2025/2026 Delivery Year and subsequent Delivery Years, Actual Performance shall not exceed the installed capacity commitment for the resource.

for each PRD Provider, the actual load reduction provided by the PRD Provider during a Performance Assessment Interval, determined in accordance with RAA, Schedule 6.1.N and the PJM Manuals; provided, however, for the 2025/2026 Delivery Year and subsequent Delivery Years, Actual Performance shall not exceed the installed capacity commitment for the resource.

for each Energy Efficiency Resource, the load reduction quantity approved by PJM subsequent to the pre-delivery year submittal of a post-installation measurement and verification report; provided, however, for the 2025/2026 Delivery Year and subsequent Delivery Years, Actual Performance shall not exceed the installed capacity commitment for the resource; and

for each Qualified Transmission Upgrade, the megawatt quantity cleared by such Qualified Transmission Upgrade if it is in service during the Performance Assessment Interval, and zero if it is not in service during such Performance Assessment Interval.

Such calculation shall encompass all resources and Price Responsive Demand located in the area defined by the Emergency Action; provided, however, that Performance Shortfall shall be calculated for external Generation Capacity Resources for any Performance Assessment Interval for which performance by such external resource would have helped resolve the declared Emergency Action that was the subject to the Performance Assessment Interval. For purposes of this provision, Qualifying Transmission Upgrades shall be deemed to be located in the Locational Deliverability Area into which such upgrade increased the Capacity Emergency Transfer Limit, and a Qualifying Transmission Upgrade shall be included in calculations of Expected Performance and Actual Performance only if, and to the extent that, the declared Emergency Action encompasses the Locational Deliverability Area into which such upgrade increased the Capacity Emergency Transfer Limit. The Performance Shortfall shall be calculated for each Performance Assessment Interval, and any committed Capacity Resource for which the above calculation produces a negative number for a Performance Assessment Interval shall not have a Performance Shortfall for such Performance Assessment Interval.

(d) Notwithstanding subsection (c) above, through the 2024/2025 Delivery Year, a Capacity Resource or Locational UCAP of a Capacity Market Seller or Locational UCAP Seller shall not be considered in the calculation of a Performance Shortfall for a Performance Assessment Interval to the extent such Capacity Resource or Locational UCAP was unavailable during such Performance Assessment Interval solely because the resource on which such Capacity Resource or Locational UCAP is based was on a Generator Planned Outage or Generator Maintenance Outage approved by the Office of the Interconnection, or was not scheduled to operate by the Office of the Interconnection, or was online but was scheduled down, by the Office of the Interconnection, based on a determination by the Office of the Interconnection that such scheduling action was appropriate to the security-constrained economic dispatch of the PJM Region. Such a resource shall be considered in the calculation of a Performance Shortfall if it otherwise was needed and would have been scheduled by the Office of the Interconnection to perform, but was not scheduled to operate, or was scheduled down, solely due to: (i) any operating parameter limitations submitted in the resource’s offer, or (ii) the seller's submission of a market-based offer higher than its cost-based. In addition, notwithstanding subsection (c) above, a Price Responsive Demand registration shall not be considered in the calculation of a Performance Shortfall or Bonus Performance for a Performance Assessment Interval when the PRD Curve associated with such registration in the PJM Real-time Energy Market indicates a price point where no demand reduction is expected at the real-time LMP recorded during the Performance Assessment Interval.

(d-1). Notwithstanding subsection (c) above, effective with the 2025/2026 Delivery Year and subsequent Delivery Years, a Capacity Resource or Locational UCAP of a Capacity Market Seller or Locational UCAP Seller shall not be considered in the calculation of a Performance Shortfall for a Performance Assessment Interval to the extent such Capacity Resource or Locational UCAP was unavailable during such Performance Assessment Interval solely because the resource on which such Capacity Resource or Locational UCAP is based was on a Generator Planned Outage or Generator Maintenance Outage approved by the Office of the Interconnection. Further, the megawatts of a Capacity Resource that was scheduled to operate at a level below its expected performance shall also be excluded from the calculation of a Performance Shortfall for a Performance Assessment Interval to the extent such scheduling was not solely due to any operating parameter limitations submitted in the resource's schedule on which it was dispatched. Notwithstanding the foregoing, except for a Capacity Resource that is on a Generator Planned Outage or Generator Maintenance Outage approved by the Office of the Interconnection, a Capacity Resource that is offline during a Performance Assessment Interval shall be included in the calculation of a Performance Shortfall unless the Office of the Interconnection affirmatively denies a request to come online for such resource. In addition, notwithstanding subsection (c) above, a Price Responsive Demand registration shall not be considered in the calculation of a Performance Shortfall for a Performance Assessment Interval when the PRD Curve associated with such registration in the PJM Real-time Energy Market indicates a price point where no demand reduction is expected at the real-time LMP recorded during the Performance Assessment Interval.

(e) Subject to the Non-Performance Charge Limit specified in subsection (f) hereof, each Capacity Market Seller and Locational UCAP Seller shall be assessed a Non-Performance Charge, which are auction clearing revenue adjustments and do not constitute a penalty rate or penalty provision, for each of its Capacity Resources or Locational UCAP that has a Performance Shortfall for a Performance Assessment Interval based on the following formula, applied to each such resource:

Non-Performance Charge = Performance Shortfall * Non-Performance Charge Rate

Where

For Capacity Performance Resources, Price Responsive Demand, and Seasonal Capacity Performance Resources, the Non-Performance Charge Rate = (Net Cost of New Entry (stated in terms of installed capacity) for the LDA and Delivery Year for which such calculation is performed * (the number of days in the Delivery Year / 30) / (the number of Real-Time Settlement Intervals in an hour).

(f) Through the 2024/2025 Delivery Year, the Non-Performance Charges for each Capacity Performance Resource (including Locational UCAP from such a resource) and each PRD Provider for a Delivery Year shall not exceed a Non-Performance Charge Limit equal to 1.5 times the Net Cost of New Entry times the megawatts of Unforced Capacity committed by such resource or such PRD Provider times the number of days in the Delivery Year. All references to Net Cost of New Entry in this section 10A shall be to the Net Cost of New Entry for the LDA and Delivery Year for which the calculation is performed. The Non-Performance Charges for each Seasonal Capacity Performance Resource for a Delivery Year shall not exceed a Non-Performance Charge Limit equal to 1.5 times the Net Cost of New Entry times the megawatts of Unforced Capacity committed by such resource times the number of days in the season applicable to such resource.

(g) Revenues collected from assessment of Non-Performance Charges for a Performance Assessment Interval shall be distributed to each Market Participant, whether or not such Market Participant committed a Capacity Resource or Locational UCAP for a Performance Assessment Interval provided that energy or load reductions above the levels expected for such resource during such interval prior to 2025/2026 Delivery Year. Beginning with the 2025/2026 Delivery Year and subsequent Delivery Years, revenues collected from assessment of Non-Performance Charges for a Performance Assessment Interval shall be distributed to Market Participants of committed Generation Capacity Resources or Locational UCAP for a Performance Assessment Interval. For purposes of this provision, the performance expected of a resource, and the revenue distribution payment, if any, for a resource, shall be determined in accordance with the following formulae:

Formula 1: Market Participant Bonus Performance = Actual Performance – Expected Performance

and

Formula 2: Performance Payment = (Market Participant Bonus Performance / All Market Participants Bonus Performance) * Non-Performance Charge Revenues.

Where the result of Formula 1 is a positive number and where:

> Actual Performance is as defined in subsection (c), provided, however, that Actual Performance for purposes of this calculation shall not exceed the megawatt level at which such resource was scheduled by the Office of the Interconnection during the Performance Assessment Intervals; and provided further that Actual Performance for a Market Participant that imports energy into the PJM Region during such Performance Assessment Interval shall be the net import, if any, from all interchange transactions scheduled by such Market Participant during such Performance Assessment Interval;
>
> Expected Performance is as defined in subsection (c), provided, however, that for purposes of this calculation, Expected Performance shall be zero for any resource that is not a Capacity Resource or Locational UCAP, or that is a Capacity Resource or Locational UCAP, but for which the Performance Assessment Interval occurs outside the

resource's capacity obligation period; and

All Market Participants Bonus Performance is the sum of the results of calculating Formula 1 of this subsection (g) for all Market Participants that have Bonus Performance during such Performance Assessment Interval.

(h) The Office of the Interconnection shall bill charges and credits for performance during Performance Assessment Intervals within three calendar months after the calendar month that included such Performance Assessment Intervals, provided, for any Non-Performance Charge, the amount shall be divided by the number of months remaining in the Delivery Year for which no invoice has been issued, and the resulting amount shall be invoiced each such remaining month in the Delivery Year. Notwithstanding, if there are less than six months remaining in the current Delivery Year for which no invoice has been issued, the Office of the Interconnection may, with prior notice to PJM Members, allocate in equal amounts any Non-Performance Charge in the remaining monthly bills for the current Delivery Year plus up to six monthly bills into the following Delivery Year for all Capacity Market Sellers that incur such a Non-Performance Charge (but in no event shall the total Non-Performance Charge be divided in more than nine monthly bills). Provided, for any Non-Performance Charges associated with Performance Assessment Intervals from December 23, 2022 and December 24, 2022, a Capacity Market Seller may elect, by providing notice to the Office of Interconnection by March 17, 2023, to divide the total amount of Non-Performance Charges by either (i) the number of remaining monthly bills in the current Delivery Year (i.e., 3 bills) or (ii) the number of remaining monthly bills in the current Delivery Year plus six additional monthly bills into the following Delivery Year (i.e., 9 bills); provided further, however, that for an election under subsection (ii) above, the monthly Non-Performance Charge shall be levelized to include interest for the six month period following the current Delivery Year, such interest amount being determined at the electric interest rate established by the Federal Energy Regulatory Commission at the time of such election. All interest collected in accordance with this provision shall be allocated to the total pool of bonus performance payments and distributed in accordance with Tariff, Attachment DD, section 10A(g).

Sections of the
PJM Reliability Assurance Agreement

(Clean Format)

C. Election, and Termination of Election, of FRR Alternative

1. No less than four months before the conduct of the Base Residual Auction for the first Delivery Year for which such election is to be effective, any Party seeking to elect the FRR Alternative shall notify the Office of the Interconnection in writing of such election. Such election shall be for a minimum term of five consecutive Delivery Years. No later than one month before such Base Residual Auction, such Party shall submit its FRR Capacity Plan demonstrating its commitment of Capacity Resources for the term of such election sufficient to meet such Party's Daily Unforced Capacity Obligation (and all other applicable obligations under this Schedule) for the load identified in such plan. Through the 2024/2025 Delivery Year, no later than the last business day prior to the start of the relevant Delivery Year in which Capacity Performance requirements shall apply to such FRR Entity, the FRR Entity must also elect whether it seeks to be subject to the Non-Performance Charge for Capacity Performance Resources and Seasonal Capacity Performance Resources, as provided in Tariff, Attachment DD, section 10A, and described in section G.1 of this Schedule 8.1, or to physical non-performance assessments, as described in section G.2 of this Schedule 8.1. Beginning with the 2025/2026 Delivery Year, the FRR Entity shall be subject to the Non-Performance Charge in accordance with Tariff, Attachment DD, section 10A, and described in RAA, Schedule 8.1.G.

2. An FRR Entity may terminate its election of the FRR Alternative effective with the commencement of any Delivery Year following the minimum five Delivery Year commitment by providing written notice of such termination to the Office of the Interconnection no later than two months prior to the Base Residual Auction for such Delivery Year. An FRR Entity that has terminated its election of the FRR Alternative shall not be eligible to re-elect the FRR Alternative for a period of five consecutive Delivery Years following the effective date of such termination.

3. Notwithstanding subsections C.1 and C.2 of this Schedule, in the event of a State Regulatory Structural Change, a Party may elect, or terminate its election of, the FRR Alternative effective as to any Delivery Year by providing written notice of such election or termination to the Office of the Interconnection in good faith as soon as the Party becomes aware of such State Regulatory Structural Change but in any event no later than two months prior to the Base Residual Auction for such Delivery Year.

4. To facilitate the elections and notices required by this Schedule, except a new FRR Entity's initial election, the Office of the Interconnection shall post, in addition to the information required by Section 5.11(a) of Attachment DD to the PJM Tariff, the percentage of Capacity Resources required to be located in each Locational Deliverability Area by no later than one month prior to the deadline for a Party to provide such elections and notices.

G. Capacity Resource Performance

1. Any Capacity Resource committed by an FRR Entity in an FRR Capacity Plan for a Delivery Year shall be subject during such Delivery Year to the charges set forth in Tariff, Attachment DD, section 7, Tariff, Attachment DD, section 9, Tariff, Attachment DD, section 10, Tariff, Attachment DD, section 10A, Tariff Attachment DD, section 11, Tariff, Attachment DD, section 11A, and Tariff, Attachment DD, section 13; provided, however: (i) the Daily Deficiency Rate under Tariff, Attachment DD, section 7, Tariff, Attachment DD, section 9, Tariff, Attachment DD, section 11A, and Tariff, Attachment DD, section 13 shall be 1.20 times the Capacity Resource Clearing Price resulting from all RPM Auctions for such Delivery Year for the LDA encompassing the Zone of the FRR Entity, weight-averaged for the Delivery Year based on the prices established and quantities cleared in such auctions); (ii) the charges set forth in Tariff, Attachment DD, section 10A shall apply only for the 2019/2020 and subsequent Delivery Years and only to those FRR Entities which opted to be subject to the Non-Performance Charge under section C.1 of this Schedule 8.1 and the charge rates under section 10A thereof for Base Capacity Resources shall be the Capacity Resource Clearing Price resulting from the RPM Auctions for the Delivery Year for the LDA encompassing the Zone of the FRR Entity, weight-averaged as described above; and (iii) the charge rates under Tariff, Attachment DD, section 10 and Tariff, Attachment DD, section 11, shall be the Capacity Resource Clearing Price resulting from the RPM Auctions for the Delivery Year for the LDA encompassing the Zone of the FRR Entity, weight-averaged as described above. An FRR Entity shall have the same opportunities to cure deficiencies and avoid or reduce associated charges during the Delivery Year that a Market Seller has under Tariff, Attachment DD, section 7, Tariff, Attachment DD, section 9, Tariff, Attachment DD, section 10, Tariff, Attachment DD, section 10A, Tariff, Attachment DD, section 11, and Tariff, Attachment DD, section 11A. An FRR Entity may cure deficiencies and avoid or reduce associated charges prior to the Delivery Year by procuring replacement Unforced Capacity outside of any RPM Auction and committing such capacity in its FRR Capacity Plan.

2. Through the 2024/2025 Delivery Year, for any FRR Entity which opted to be subject to physical non-performance assessments under RAA, Schedule 8.1, section C.1, such FRR Entity will not be subject to charges under Tariff, Attachment DD, section 10A, but, rather, it will be required to update its FRR Capacity Plan with additional megawatts of Capacity Performance Resources or Seasonal Capacity Performance Resources determined in accordance with the following: For each Performance Assessment Interval, the Actual Performance and Expected Performance of each resource contained in an FRR Entity's FRR Capacity Plan or Price Responsive Demand committed to reduce the FRR Entity's unforced capacity obligation will be determined in the same fashion as prescribed by the Tariff, Attachment DD, section 10A. The net Performance Shortfall determined for Capacity Performance Resources and Price Responsive Demand shall include the performance of Seasonal Capacity Performance Resources contained in the FRR Capacity Plan.

The FRR Entity's net Performance Shortfall among Capacity Performance Resources or Price Responsive Demand, if any, for each such Performance Assessment Interval shall be multiplied by a rate of 0.00139 MWs/Performance Assessment Interval to establish the additional MW quantities of Capacity Performance Resources, Seasonal Capacity Performance Resources, or Price Responsive Demand that such FRR Entity must add to its FRR Capacity Plan for the next

Delivery Year. Notwithstanding the foregoing, the total additional MWs required as a result of non-performance by the FRR Entity's Capacity Performance Resources in any Delivery Year shall not exceed a MW quantity equal to 0.5 times the MW quantity of the Capacity Performance Resources and Seasonal Capacity Performance Resources that were committed in the FRR Capacity Plan for such Delivery Year and Price Responsive Demand committed such Delivery Year.

An FRR Entity that elects the physical option shall not be eligible for, or subject to, the revenue allocation described in Tariff, Attachment DD, section 10A(g).

Attachment C

Affidavit of Adam Keech
on Behalf of
PJM Interconnection, L.L.C.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	)))	**Docket No. ER24-___-000**

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

Qualifications

1. My name is Adam Keech. My business address is 2750 Monroe Blvd., Audubon, Pennsylvania, 19403. I am the Vice President of Market Design and Economics at PJM Interconnection, L.L.C. ("PJM"). I am submitting this affidavit on behalf of PJM in support of its capacity market reform filing. In my current role I oversee the design of all of the wholesale markets operated by PJM and the development of large-scale advanced analyses such as those done for carbon pricing and renewable integration. I am also responsible for the applied innovation area that focuses on evaluating, leveraging and supporting the implementation of advanced solutions in the planning, markets and operations areas. I have worked for PJM since 2003 and held senior leadership roles in both the Market Services and System Operations divisions. I earned a Bachelor of Science in electrical engineering from Rutgers University in 2002 and earned a Master of Science in applied statistics from West Chester University in 2013.

Purpose of This Affidavit

2. The purpose of my affidavit is to first explain the importance of the capacity market's role as part of the overall suite of PJM's markets and describe the motivation to seek changes now. As explained in my affidavit and in various other work performed by PJM, the industry is in a period of rapid change. While the foundation of PJM's markets is strong, it is necessary to evaluate their designs in light of the change in the industry to ensure they are configured to continue to provide reliability at low cost to consumers and send efficient price signals for performance, entry and exit. From there I go on further to explain the rationale for specific, necessary, enhancements including a move to marginal accreditation, stronger testing requirements and a collection of changes to the Fixed Resource Requirement option.

Why is the Capacity Market Necessary?

3. The capacity market is necessary because the energy and ancillary services ("E&AS") markets do not consistently produce sufficient revenues to support investment in sufficient resources to maintain the desired level of reliability (one

loss of load event in ten years, on average). This lack of revenues, or "missing money", comes from two primary causes:

a. Limitations on the revenues permitted to be settled in the E&AS due to rules such as offer and price cap levels, and,

b. A desire not to shed load at a frequency greater than one event every ten years, on-average.

4. The purpose of my affidavit is not to argue merits of those rules; however, it is helpful to understand them as key drivers that lead to the "missing money" problem that PJM uses the Reliability Pricing Model (RPM) to address.

5. At its core, capacity is a reserve product. The product itself is generation or load curtailment capability to provide enough supply to, at a minimum, meet the desired level of reliability. The revenues from the sale of the product go directly towards addressing the revenue gap between those produced by the E&AS markets and those necessary to meet the desired level of reliability. PJM uses a uniform clearing price market to procure the capacity product at least cost in the short- and long-term by harnessing the benefit of competition.

6. In the PJM market where approximately 70% of the load is in a state that has restructured its retail electricity market, a functioning capacity market like the RPM is required to procure adequate supply to meet the desired level of reliability in any given Delivery Year. In general, supply resources in restructured states do not receive cost recovery through a state agency and therefore rely on the capacity market and E&AS markets in PJM for the vast majority their revenues. Failure of the capacity market to perform can result in a shortfall supply relative to the amount necessary to maintain desired level of reliability resulting in frequent load-shedding events, or excess capacity whose costs exceed its reasonable incremental impact to reliability. Neither of these outcomes are desirable and therefore careful thought must be put into the various parameters of the capacity market to result in just and reasonable outcomes.

Why Are We Changing the Capacity Market?

7. Since the start of the Resource Adequacy Senior Task Force (RASTF) in late-2021, a primary motivator of PJM's focus on capacity market reforms has been to enhance its resource adequacy risk modeling and accreditation methods. Historically, resource adequacy risk modeling and accreditation methods have relied on assumptions that:

a. Resource adequacy risk is aligned with peak load conditions,

b. Generator outages are independent of each other, and,

c. Average historical performance is a reasonable estimate of future performance during resource adequacy risk periods.

8. For decades, these assumptions have generally held true and have shaped the way the industry thinks about resource adequacy. However, over the last decade, evidence has emerged that these assumptions may no longer be workable and that a fresh look at resource adequacy risk modeling and accreditation is needed to provide for reliability both now and in the future.

9. In the recently released presentation titled, "December 2022 Winter Storm Elliott Grid Operations: Key Findings and Recommendations", NERC and FERC highlight that Winter Storm Elliott represents the fifth event where, "cold weather-related generation outages jeopardized bulk power system reliability".[1] Two of those five events, the 2014 Polar Vortex and Winter Storm Elliott in 2022, directly impacted PJM. In fact, the 2014 Polar Vortex spurred the implementation of Capacity Performance in 2015, and Winter Storm Elliott introduced a significant number of action items and recommendations,[2] several of which are being addressed in PJM's proposal. The statement by NERC and FERC very succinctly captures the need to reform resource adequacy risk modeling and accreditation as it highlights two issues:

   a. Bulk power system reliability was jeopardized in the winter, not summer. PJM is not a winter-peaking system in terms of load, but in recent years the resource adequacy risk has been empirically observed in the winter. This demonstrates that, at least for PJM, the existing resource adequacy risk modeling assumption of risk aligning with primarily with peak load is incorrect.

   b. The aforementioned resource adequacy risk was driven by generation outages that were correlated with temperature; in this case cold weather. This communicates a few things:

      i. Poor fleet performance, on its own, can create resource adequacy risk. This was the case in the 2014 Polar Vortex and Winter Storm Elliott in 2022. Establishing a model where resource performance can be a driver of reliability risk is essential.

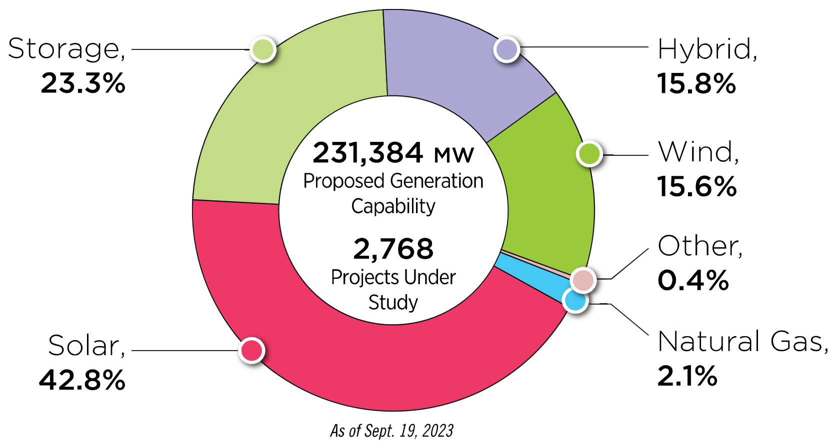
      ii. Generator outages are correlated with temperature. FERC and NERC highlight that this is the fifth instance of this in the last 11 years which demonstrates that these are not anomalous observations.

---

[1] FERC, NERC, and Regional Entity Joint Staff Inquiry, *December 2022 Winter Storm Elliott Grid Operations: Key Findings and Recommendations*, Federal Energy Regulatory Commission, 3 (Sept. 21, 2023), https://www.ferc.gov/news-events/news/presentation-ferc-nerc-regional-entity-joint-inquiry-winter-storm-elliott.

[2] *Winter Storm Elliott: Event Analysis and Recommendation Report*, PJM Interconnection, L.L.C. (July 17, 2023), https://pjm.com/-/media/library/reports-notices/special-reports/2023/20230717-winter-storm-elliott-event-analysis-and-recommendation-report.ashx.

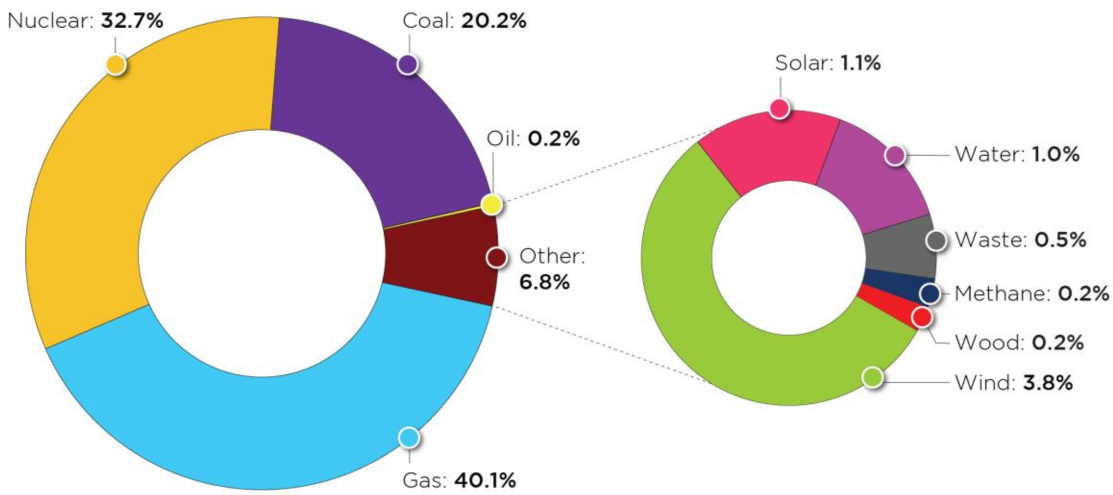
10. Further motivating the need for capacity market reform is the ongoing energy transition. As shown in Figure 1, PJM's current generation interconnection queue is primarily composed of solar, storage, hybrid resources and wind. Today in PJM, the penetration levels of these resource types are relatively low in comparison to the shares that exist in the queue and what is interconnected in other ISO/RTOs. PJM anticipates that the penetration of these resources will increase in the future based on what is in the PJM generation interconnection queue and the continued growth of these resource types in other areas of the country. Because these resources have different operating profiles than those that they stand to replace[3], implementing a method to accurately value the capacity capability of these resources and assess how their performance effects resource adequacy risk is critical to maintaining resource adequacy through the energy transition.



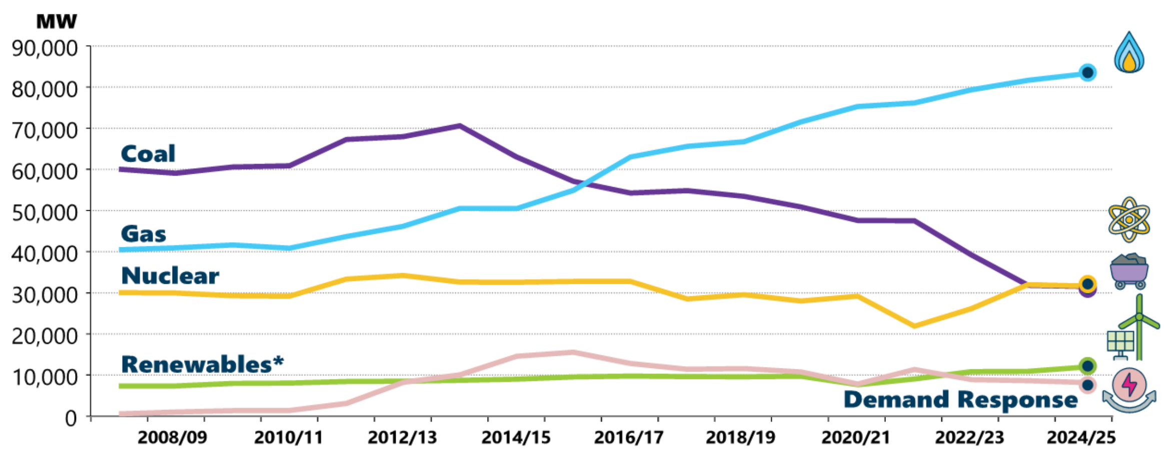
11. Another event that has already substantially impacted the demographics of the PJM generation fleet is the "shale gas revolution" that has occurred over roughly the last decade. This has resulted in the transition to natural gas as the primary fuel for the production of energy in PJM and the primary resource type providing capacity in PJM.

[3] Different operating profiles between solar, wind, storage and hybrid resources include, for solar and wind, correlation between output level and weather conditions that may not align with resource adequacy risk periods and for storage and hybrid resources, energy limitations related to storage capability and weather conditions.

2022 PJM Fuel Mix



Committed Unforced Capacity in PJM



**Renewables include solar, wind, hydro and wood. Note: All values include capacity cleared in RPM BRA or committed in FRR plan*

12. Many of these new gas-fired resources are incredibly flexible and provide much-needed reliability attributes. However, their performance is subject to the rules and restrictions of the interstate natural gas pipeline and production systems which, in terms of resource adequacy risk modeling, represents a common-mode failure that was a factor in their performance during the 2014 Polar Vortex and Winter Storm Elliott that led to resource adequacy risk. In PJM, changes to the resource fleet that have already occurred from the "shale gas revolution" and stand to occur due to the energy transition stand to create a generation fleet whose performance is more dependent on exogenous factors than ever experienced with previous resource mixes. In the case of renewable resources, they are dependent on weather patterns that do not always align with resource adequacy risk conditions. In the case of natural gas-fired resources, upstream limitations on pipeline capacity and production can adversely affect a broad set of resources in the PJM footprint simultaneously. These common-mode failures of supply-side resources are not

accurately represented in the current resource adequacy risk modeling and accreditation approaches and on their own can result in resource adequacy risk.

13. The need to depart from the legacy assumptions of (i) the alignment of resource adequacy risk with peak load conditions, (ii) independence of generator outages, and (iii) using average availability as an estimate of performance during risk periods, has required PJM to significantly enhance its resource adequacy risk modeling and accreditation approach to incorporate hourly granularity and the explicitly modeling of correlated outages as described in detail by Dr. Rocha-Garrido. These changes will more robustly determine periods of resource adequacy risk and more accurately estimate resource performance during those risk periods. In turn, these changes will allow PJM to better accredit the capacity capability of each resource by identifying each resource's relative reliability value to the PJM Region. Further, these changes have downstream impacts on the parameters that apply to the capacity market and the incentives that need to be sent to maintain resource adequacy cost-effectively in the short- and long-term.

Marginal Accreditation

14. Capacity accreditation is the process whereby PJM converts the nameplate capability of a resource to an accredited level of capacity that it may offer to sell in an auction. Under today's rules PJM uses average Effective Load Carrying Capability (ELCC) for intermittent, storage and combination resources, Equivalent Demand Forced Outage Rate (EFORd) for thermal resources (i.e., Unlimited Resources), and nominated capability times the Forecast Pool Requirement (FPR) for Demand Response (DR). Each of these methodologies is based on different performance assumptions for each resource type. For example, using EFORd for thermal resources assumes that the average historical performance of a thermal generator is a good approximation of future performance during risk periods. Using average ELCC for intermittent resources accredits based on the expected alignment of resource performance with risk conditions. For DR, the use of FPR as the sole component to determine accreditation assumes DR are always available during risk conditions and always perform perfectly. Each of these approaches have shortcomings but the shortcomings of each approach are different and affects accreditation of the applicable resource type in a different way.

15. Through this filing, PJM proposes to move to a marginal ELCC approach for all Capacity Resource types except of Energy Efficiency (EE) Resources.[4] Dr. Rocha-Garrido details in his affidavit how the marginal ELCC accreditation approach works. There are several drivers for this change:

    a. PJM seeks to unify its accreditation approach across all resources so there is consistency in the accreditation process.

[4] PJM Forward Market Operations, *PJM Manual 18B: Energy Efficiency Measure & Verification*, PJM Interconnection, L.L.C. (Sept. 21, 2022), https://pjm.com/~/media/documents/manuals/m18b.ashx.

b. The marginal accreditation approach proposed by PJM naturally aligns the level of accredited capacity of resource with its expected performance during risk periods.

c. The marginal accreditation approach proposed by PJM sends investment signals that are consistent with the marginal benefit to reliability (in this proposal Expected Unserved Energy (EUE)) of a specific resource or class. This creates incentives to invest in resources and resource classes that directly benefit resource adequacy needs.

16. A consistent accreditation approach is important in treating the various supply resources in the capacity market and creating a reasonably uniform capacity product across the various resource types. Under the current rules it could be argued that certain resource classes may be advantaged, or disadvantaged, just because of the accreditation approach that is applied to them. The benefit of a single accreditation approach is even more critical because it creates a single, fungible capacity product which could be argued to not be the case under the current rules given the various accreditation methods used. A simple example is that the EFORd approach applied to thermal resources today values average historic performance without focused consideration of performance during risk periods, whereas the use of ELCC for intermittent, storage and combination resources values performance coincident with risk periods. The result is two different products that are not fungible yet are treated as such in the current design. A single accreditation approach for all resources addresses this issue. Using one method to accredit resources results in a common definition of the capacity product across the various resource types and allows for the creation of a single, fungible product.

17. The marginal ELCC approach proposed by PJM calculates the marginal benefit to reliability, measured as a reduction in EUE, resulting from an incremental increase in nameplate capability of that class. Each class-level marginal ELCC is then propagated to individual resources within the class based on each individual resource’s actual performance relative to others in the same class. Accrediting in this manner for all resources establishes a uniform capacity product across each resource participating in the market but also has the secondary benefit of aligning the level of accredited capacity for a resource with its expected performance during periods of risk as identified in the resource adequacy risk models explained by Dr. Rocha-Garrido. This is a beneficial change because it more precisely estimates how a resource will perform during identified periods of resource adequacy risk rather than assuming average performance (EFORd) or perfect performance (current accreditation method for DR). Accrediting capacity resources based on expected performance during risk periods is critical to ensuring that the actual resource adequacy needs of the system are being met and that consumers paying for capacity are get the reliability they are paying for.

18. As an example, assume a 100 MW thermal resource is on a forced outage 5% of the time (438 hours per year) such that under the current rules it has 95 MW of accredited capacity. Under the current rules and with respect to accreditation, those

438 hours of forced outage can occur at any time during the year and it will result in the same accredited level of capacity. Whether the 438 hours of forced outages overlap with the riskiest hours in the year or they do not, the accredited value of capacity is the same. This is a major downside of average accreditation methods, that is, consumers pay for performance on average rather than specifically for performance during resource adequacy risk periods for which they purchase capacity. In the case of PJM today, Capacity Performance and the associated Non-Performance Charges and bonus payments send incentives to perform during risk hours, however, those events are infrequent in nature and absent aligning accreditation with expected performance during risk periods, consumers could pay such a resource for capacity, possibly for years in between events when the resource does not actually contribute to reliability consistent with the revenues it is collecting.

19. Marginal ELCC as proposed by PJM sends investment signals that are consistent with the marginal reliability benefit of a resource resulting in strong incentives to invest in resources that directly improve resource adequacy (measured as a reduction in EUE). In general, this occurs because the capacity product itself as defined by using marginal ELCC represents a resource's incremental benefit to reliability. Resources that do not perform well during risk conditions have lower contributions to overall system reliability, will have lower accredited levels and as such will collect less revenues than resources that perform well during risk periods and reduce the system's EUE. Dr. Graf explains this concept further through simulations in his affidavit.

20. Finally, the shift to a marginal accreditation approach is consistent with other ISO/RTOs which either have, or are working towards, similar enhancements. For instance, NYISO filed a marginal accreditation approach with the Commission in 2022 that has been accepted.[5] ISONE is currently working towards implementing a marginal accreditation approach, as is MISO. The movement of other ISO/RTOs towards marginal accreditation and the fact that the Commission has already found this approach to be just and reasonable gives further credence to the method. This approach represents the industry's best-known method to model the various factors that can influence resource performance during risk periods using standard statistical algorithms and results in market outcomes that incentivize investment in resources that benefit resource adequacy at least cost.

<u>Testing</u>

21. PJM is proposing several changes to its testing requirements that will require a demonstration of resource capability in both the summer and winter seasons and improve operational readiness prior to extreme weather events. The purpose of making these changes is to better balance the financial incentives for performance conveyed through Capacity Performance with actual demonstrations of capacity

---

[5] *N.Y. Indep. Sys. Operator, Inc.*, 179 FERC ¶ 61,102 (2022).

resource capability prior to the Performance Assessment Intervals where Non-Performance Charges and bonus payments may apply.

22. PJM proposes three key changes:

a. An additional requirement for capacity resources to physically perform a capability test in the winter in addition to the current requirement for summer capability testing, and,

b. A change to the calculation of the MW shortfall used to determine whether a Generation Resource Test Failure Charge applies from the current average method to a daily assessment, and,

c. The creation of a new test called the Generator Operation Test intended to test resource capability and operating parameter accuracy prior to periods of the year where PJM may experience extreme weather conditions.

23. PJM's current Generation Capacity Resource capability testing rules require only a single test to be conducted in the summer and permits the use of ambient temperature adjustments from the summer test result to demonstrate winter capability. At the end of each Delivery Year, the annual average of the installed capacity committed on each resource is compared to the highest installed capacity rating determined for the resource during the relevant summer or winter testing period and any shortfalls are assessed a Generation Resource Rating Test Failure Charge. The Generation Resource Rating Test Failure Charge is equal to the Daily Deficiency Rate multiplied by the MW shortfall where the Daily Deficiency Rate is the higher of the $20/MW-day or 1.2 * Weighted Average Clearing Price that the resource receives for the Delivery Year based on the MW quantities and clearing prices it receives from each auction it cleared in.

24. There are two shortcomings with this approach that PJM seeks to amend with this proceeding. First, empirical observations from Winter Storm Elliott and similar extreme events in other ISO/RTOs, as well as the analysis performed by Dr. Rocha-Garrido to determine the ELCC for capacity resources, clearly demonstrate that generators operate differently in the summer and winter. These observation and analyses indicate that the current method of extrapolating winter capability from summer capability through ambient temperature adjustments is not suitable to determine the true winter capability of a generation resource. The best way to assess both summer and winter capability is by requiring physical demonstrations of this capability in each season. As such, PJM proposes to require seasonal rating tests for each generation capacity resource with the details of those test to be defined in PJM manuals as they are today.

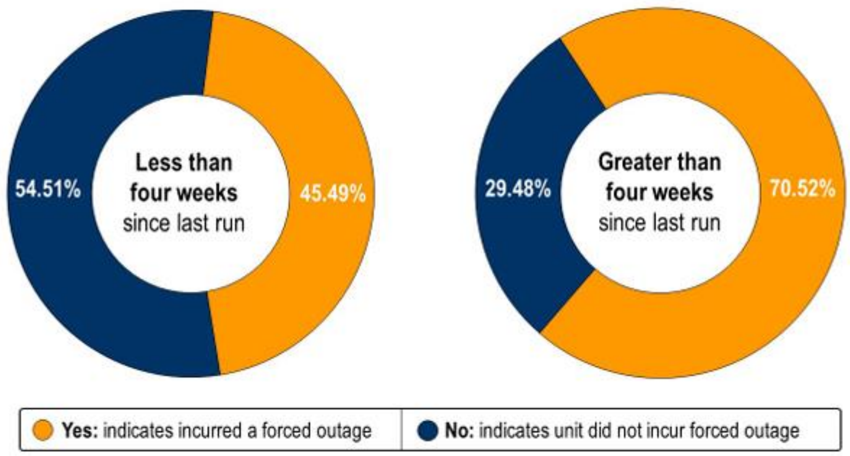
25. The second proposed change to the Generation Capacity Resource capability testing process is with regard to the calculation of the MW shortfall portion of the Generation Resource Test Failure Charge. Currently the Generation Resource Rating Test Failure Charge is calculated at the end of each Delivery Year and

includes MW shortfall calculation based on the *annual average* of the installed capacity committed on each resource minus the highest installed capacity rating determined for the resource during the relevant summer or winter testing period. That MW shortfall is then converted to an unforced capacity basis, and multiplied by the Daily Deficiency Rate. PJM's proposed change is with regard to the calculation of the MW shortfall only. PJM is not proposing to change the Daily Deficiency Rate. Rather, in calculating the MW shortfall, PJM proposes to assess the resource's MW shortfall on the daily installed capacity commitment of the resource instead of the annual average of the installed capacity committed on the resource. The rationale for this change is to more precisely determine whether the installed capacity the resource is committed for each day aligns with its demonstrated capability. The current process of using an annual average is directionally reasonable but can miss scenarios where on any given day a resource's committed installed capacity is higher than its demonstrated seasonal capability but when averaged annually is missed. The objective of this change is to have greater confidence that for every single day of the Delivery Year, each resource has demonstrated the capability to meet its capacity commitment. If it cannot, it will be assessed as deficient and subject to a Generation Resource Rating Test Failure Charge.

26. The third proposed change to Generation Capacity Resource testing is the implementation of a new testing process called Generation Capacity Resource Operational Testing. The purpose of this test is to have greater confidence that Generation Capacity Resources can operate successfully when called based on their submitted operating parameters. The intention of this test is to check that accurate information regarding the operational status and operating parameters of a Generation Capacity Resource are provided to PJM and that the Generation Capacity Resource can successfully demonstrate that through performance. This is particularly important for those Generation Capacity Resources that do operate frequently and may be asked to operate during a resource adequacy risk period after not running for several months.

27. The motivation for such a test comes from analysis done by PJM on generator performance during Winter Storm Elliott. Following that event, PJM analyzed and published the following chart regarding generation resource performance during Winter Storm Elliott. The following chart shows that resources that had run within a month of Winter Storm Elliott experienced a forced outage rate that was 25% percentage points lower than those that had not run as recently. This data supports the conclusion that a generator that has not operated recently and is asked to start in anticipation of or during a capacity emergency is at a higher risk of experiencing a forced outage than one that has operated more recently.

Force Outage Versus Last Run Time



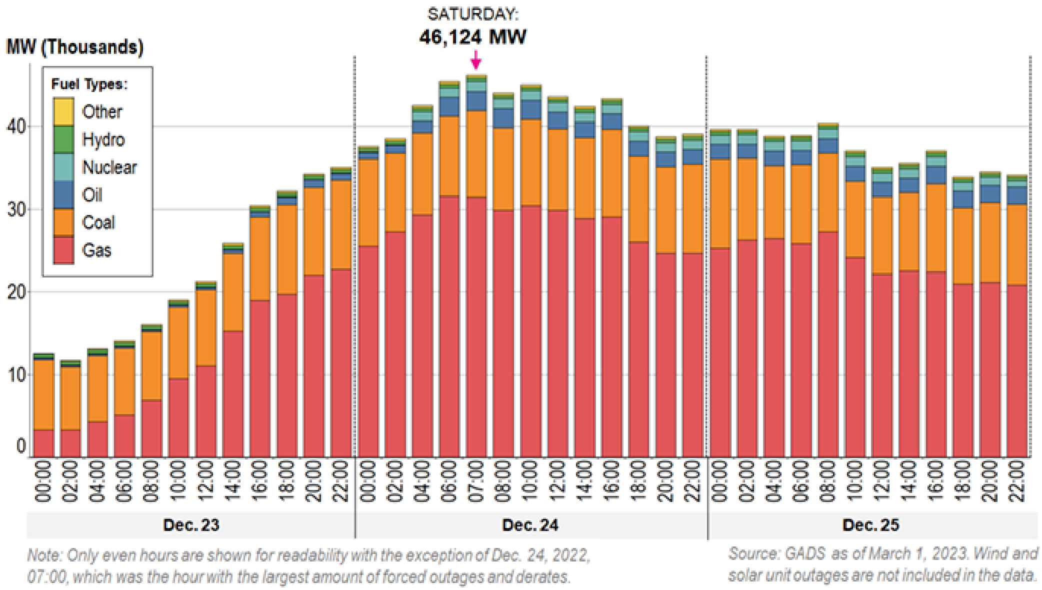
28. Further, during Winter Storm Elliott, PJM experienced a significant number of outages that were mechanical in nature. The following charts show two key points:

   a. On the first chart, approximately 75% of the generator forced outages experienced during Winter Storm Elliott were from generation resources whose fuel was natural gas, and

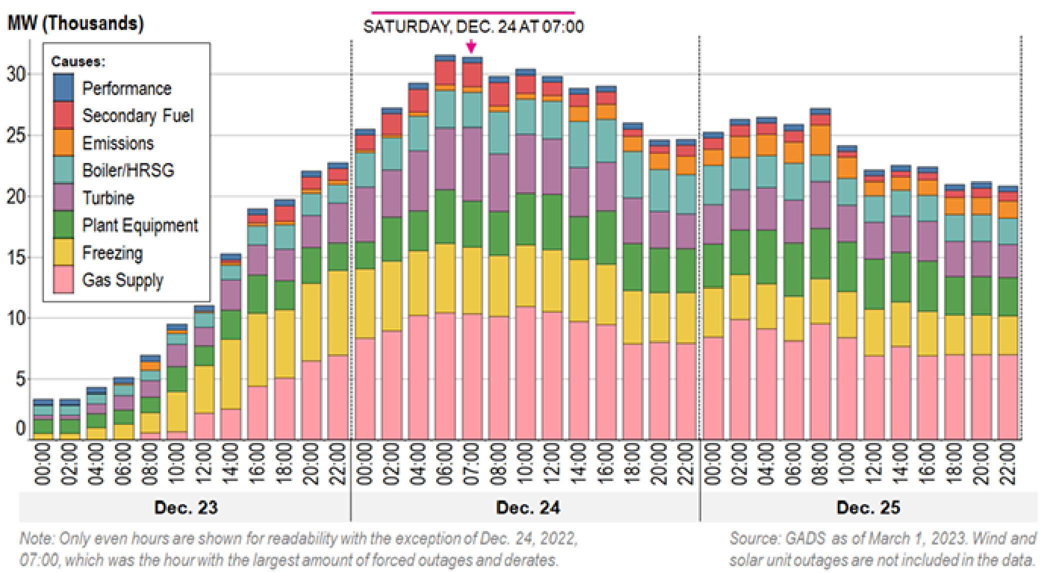
   b. On the second chart, only approximately 25% of those outages to natural gas units were related to "Gas Supply" issues.

29. In short, over 80% of the outages experienced during Winter Storm Elliott were mechanical in nature. PJM interprets this data to show that there is an opportunity to enhance testing and better balance the demonstration of performance through testing with the financial incentives conveyed through Capacity Performance. While it is impossible to test Generation Capacity Resources during Winter Storm Elliott-like or summer peak load conditions, additional operational testing will be beneficial to the early identification and correction of some mechanical issues that can help to bolster fleet performance during actual capacity emergencies.

Winter Storm Elliott Forced Outages by Fuel Type



Causes of Forced Outages to Gas Generators During Winter Storm Elliott



30. As stated previously, the purpose of this test is to confirm that Generation Capacity Resources, especially those that have not operated recently, can do so upon PJM request and according to their operating parameters. The goal is to make sure Generation Capacity Resources can operate and given them an opportunity to demonstrate that rather than to assess penalties. However, should a resource continually fail in Generation Capacity Resource Operational Testing, it demonstrates the Generation Capacity Resource's inability to perform and must eventually result in some level of financial penalty.

31. The framework of the new Generation Capacity Resource Operational Testing process gives PJM the ability to request an operational test up to two times per Generation Capacity Resource, per summer or winter season, not including re-tests. The timing of such tests shall be at the discretion of PJM. This provides PJM an opportunity to test resources during the types of system conditions that, to the degree possible, are representative of those experienced during actual reliability events. A successful test for a Generation Capacity Resource demonstrates the following abilities:

   a. Start within the startup and notification time parameters submitted with the Generation Capacity Resource's applicable energy offer, plus the greater of 10 minutes or 10%, and

   b. Operate for the entirety of the minimum run time consistent with energy market offer.

32. During the testing period, the Generation Capacity Resource will be dispatched and settled the same as any other resource operating in the PJM energy market, including any uplift to allow the resource to recover its operating cost under PJM's existing uplift provisions. If the resource fails its test, regardless of whether that failure is due to a failure to start within the provided time or meet its minimum run time parameters, PJM can issue a re-test at a future time. The retest will be the same as the initial test except that the resource will not be eligible for any uplift payments to recover testing costs, and the retest will not be counted towards the two operational tests allowed per season. If the retest is also failed, regardless of the reason, PJM may issue another re-test at a future time, and continue doing so until the resource successfully passes the test. This allows PJM to continue re-testing resources that fail, without subjecting load to further uplift payments, which improves PJM's visibility of the operational capabilities of resources, and provides an incentive for generation owners to be accurate in the operating parameters submitted to PJM and used for scheduling.

33. Furthermore, for resources that entirely fail to start up and synchronize to the grid during a re-test, a Generation Capacity Resource Operational Test Failure Charge shall apply from the point at which the resource failed the re-test until it can successfully come online and operate. This is appropriate as the resource has demonstrated through multiple failed tests an inability to provide any capacity value during this time. The charge shall be assessed against the full daily committed UCAP MW of the resource and multiplied by the same Daily Deficiency Rate as used in the Generation Resource Rating Test Failure Charge.

34. It is my belief that the Generation Capacity Resource Operational Test will result in better operational performance of the generation fleet during capacity emergencies because it specifically creates an opportunity to test the operating capability of a resource prior to the event itself. This will help to identify any operational issues with a Generation Capacity Resource before an actual emergency condition arises. Furthermore, the operational test provides a check on the reported

availability of Generation Capacity Resources, which can improve the availability and outage metrics that feed into resource accreditation for future Delivery Years. This is particularly true for resources that are reported as available for extended periods of time, but rarely scheduled to operate, as these tests provide a check on that availability and can significantly increase the number of times that the ability of the resource to successfully start up and run when scheduled is tested each year.

Fixed Resource Requirement (FRR) Changes

35. PJM is proposing to make additional changes to the FRR option to create equitable treatment between FRR entities and RPM participants and equivalent standards and methods for resource adequacy risk modeling and accreditation. As such, the changes PJM proposes to the FRR option fall in the categories of:

    a. Resource Adequacy Risk Modeling and Accreditation,

    b. Performance Assessments Including Capacity Performance and Testing,

    c. Deficiency and Insufficiency Charges, or

    d. FRR Transition.

36. A brief summary of the changes in each area and the supporting rationale are provided in the following sections.

Risk Modeling and Accreditation Implementation in the FRR Option

37. PJM proposes to apply its new methods of resource adequacy risk modeling and accreditation to FRR entities. In short, the obligations of FRR entities and the accreditation of resources in the FRR Plans will be determined using the same methods of resource adequacy risk modeling and marginal accreditation as used for loads and suppliers participating in RPM Auctions. PJM's proposed methods for risk modeling and capacity accreditation present a significant enhancement over the existing processes. Uniform standards and calculations for the determination of resource adequacy risks and accredited capacity levels need to be done consistently across the PJM Region so that there are no gaps in how risks are assessed between RPM and FRR and that resource types are not accredited uniquely simply because of the business model they operate in. This portion of the proposal simply transposes the new risk modeling and accreditation proposal onto FRR entities and makes no further changes.

Performance Assessments Including Capacity Performance and Testing in the FRR Option

38. Under today's rules, FRR entities that demonstrate under-performance during a PAI have the option to elect a "physical assessment" in which they are obligated to carry additional capacity rather than the financial assessment that occurs for RPM entities. The "physical" option allows FRR entities with under-performing

resources the option to assign more capacity in the future rather than pay Non-Performance Charges for the under-performance. This form of a penalty, which defers the penalty's effects, can severely mute incentives to perform when the system needs it the most, especially when the FRR entity has excess supply not in its FRR Plan or can readily purchase it on the market at low cost. Removal of the "physical assessment" will expose FRR entities to the same financial incentives for performance as those with RPM commitments and thus create a uniform set of performance incentives across all capacity resources during a PAI.

39. Similar to the proposal for risk modeling and accreditation, PJM plans to apply the aforementioned reforms to Generation Capacity Resource testing and the associated Non-Performance Charges from failed tests to resource's committed in an FRR Plan as well. This change is beneficial as it would maintain uniform standards for testing across all Generation Capacity Resources.

Deficiency and Insufficiency Charge Enhancements

40. To create appropriate incentives for FRR entities to have sufficient megawatts of accredited capacity in place to meet their obligations, PJM proposes to adjust the level of the FRR deficiency and insufficiency charges from the current level of 1.2 * Base Residual Auction ("BRA") Clearing Price and 2 * Gross CONE, respectively, to the price-level corresponding to Point 1 on the Locational Deliverability Area ("LDA") Variable Resource Requirement (VRR) curve where the FRR obligation exists. This change makes equal the penalty to an FRR Entity for either not having adequate capacity in its initial FRR Plan when it is due (insufficiency charge), or, being short of capacity obligation during the Delivery Year (deficiency charge). This level provides sufficiently high incentives for FRR Entities to contract with resources in a timely manner to meet their obligations. Two times gross CONE for the insufficiency charge is higher than any point on the VRR Curve used in the RPM Auctions and may be inappropriately high and punitive. Conversely, for the deficiency charge at 1.2 times the BRA clearing price, low BRA clearing price levels, such as those recently observed (e.g., $34.13/MW-Day for the 2023/2024 Delivery Year) may be low enough that it is less expensive for an FRR Entity to pay the applicable charges instead of procuring sufficient capacity to meet the requirements of its plan. This is a bad outcome from a resource adequacy perspective and therefore needs to be addressed.

41. PJM selected the price-level of Point 1 on the applicable LDA VRR curve because the obligation of an FRR Entity is set based on the FPR which represents the amount of UCAP required to maintain the one-day-in-ten-years Loss of Load Expectation standard. Failure to meet that falls short of the target level of reliability and should correspond to a high penalty rate to incentivize curing the shortfall expeditiously. Additionally, the price associated with Point 1 on the applicable LDA VRR curve also generally corresponds to the maximum price level loads participating the in the BRA would pay if the RPM Auction cleared short of the reliability target. While they are not exact, using the price-level associated with Point 1 on the LDA VRR

curve is a reasonable proxy given that it is already an accepted anchor point on the VRR curves used in the BRA

42. For these reasons, it is reasonable for FRR entities to be subject to a similar economic signal to avoid being short of capacity in their FRR Plans.

FRR Transition

43. In recognition of the relatively longer lead times necessary for capacity planning in FRR regions, the significance of changes proposed in the filing, the relatively short timeframe in which such changes will be implemented, and the unique circumstances that FRR entities are in due to their inability to purchase capacity in an RPM Auction, PJM proposes a transition mechanism for FRR entities containing two elements:

    a. PJM proposes to allow a one-time option for FRR entities who have not yet met the minimum five-year commitment to the FRR election to re-join RPM beginning with the 2025/2026 BRA and carrying through the 2028/2029 BRA. Note that an election to re-join RPM during those years still requires a five-year minimum commitment period as applies under the current rules, meaning that entities will not be free to jump in and out of the market.

    b. For FRR entities remaining in the FRR option, PJM proposes to waive, for a four-year period, the insufficiency charge that applies when an FRR entity is unable to demonstrate at the time the initial FRR plan is due, that they have enough resources to meet their projected obligation. The waiving of this charge for the same period of Delivery Years simply allows FRR entities more time to meet their obligations without the assessment of an insufficiency charge.

44. The overall objective of this transition proposal is ultimately to procure all the resource adequacy needs of the entire PJM Region, either through RPM Auctions or through FRR Plans. FRR Entities concerned about being able to meet their obligation can re-join RPM, which would grant them access to sell their resources in RPM Auctions and purchase capacity from the pool. FRR Entities who remain in the FRR Alternative would be granted more time to procure or build Capacity Resources without being subject to insufficiency charges. This is appropriate given the magnitude of the changes and relatively quick implementation schedule. This is a reasonable transition proposal considering the unique circumstances that FRR entities are in.

45. This concludes my affidavit.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
PJM Interconnection, L.L.C.	**)**	**Docket No. ER24-___-000**
	)	

I, Adam Keech, pursuant to 28 U.S.C. § 1746, state, under penalty of perjury, that I am the Adam Keech referred to in the foregoing document entitled "Affidavit of Adam Keech on Behalf of PJM Interconnection, L.L.C.," that I have read the same and am familiar with the contents thereof, and that the facts set forth therein are true and correct to the best of my knowledge, information, and belief.

/s/ Adam Keech
Adam Keech
Vice President of Market Design and Economics
PJM Interconnection, L.L.C.

Dated: October 13, 2023

Attachment D

Affidavit of Dr. Walter Graf
on Behalf of
PJM Interconnection, L.L.C.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL REGULATORY COMMISSION

	)	
PJM Interconnection, L.L.C.	)	**Docket No. ER24-__-000**
	)	

AFFIDAVIT OF DR. WALTER GRAF
ON BEHALF OF PJM INTERCONNECTION, L.L.C.

I. QUALIFICATIONS

1. My name is Dr. Walter Graf. I am the Chief Economist for PJM Interconnection, L.L.C. ("PJM"). My business address is 2750 Monroe Blvd, Audubon, PA 19403.

2. In my current position my core function is to advise the executive team and staff of the market services division on all economic policy and economic analysis activities related to market operations, design, and long-term evolution, across all PJM markets including the energy, ancillary services, capacity, and financial transmission rights markets. My responsibilities include: providing analysis of operational, economic, and accounting data on the overall performance of the competitive wholesale electricity markets; supporting the development of a strategic direction of PJM's activities in market development and evolution; performing qualitative and quantitative economic analysis of proposed changes to the PJM market rules; and supporting the stakeholder process in related areas.

3. Prior to my current position I was Senior Director, Economics for PJM, before which I was Associate and Senior Associate at The Brattle Group, an economic consulting firm. Among other engagements, I worked for regulators, market operators, and market participants on matters related to resource adequacy in five jurisdictions worldwide. I provided economic expertise, analysis, and recommendations on design decisions involving resource qualification and capacity value rating methodologies; demand curve design; auction format and mechanics; market power mitigation approach, thresholds, and unit-specific reviews; performance obligations and incentives; cost allocation to retailers and consumers; and assessment of cost impacts to customers.

4. I received Bachelors of Science degrees in Economics and in Civil and Environmental Engineering from the University of Michigan in Ann Arbor, MI. I received a Masters of Science degree and a Doctor of Philosophy degree in Agricultural and Resource Economics from the University of California in Berkeley, CA.

II. OVERVIEW AND PURPOSE OF AFFIDAVIT

5. I am submitting this affidavit on behalf of PJM in support of its proposed changes to the Reliability Pricing Model ("RPM"). The substantial changes PJM proposes

are intended to better align the RPM, or "capacity market," with the twin objectives of reliability and efficiency:

a. **Reliability:** securing adequate resources to meet a target loss of load metric.

b. **Efficiency:** upholding competitive principles and providing transparent price signals for efficient entry and exit of resources. In this context, efficiency means achieving the maximum possible reliability for a given societal cost, or minimizing societal costs for the delivered level of reliability.

6. Fundamentally, the PJM Reliability Pricing Model is an administrative framework, grounded in market principles, which PJM employs to procure a capacity "product" to sustain long-term reliability and efficiency. The capacity product is a reserve-like commitment to be available and perform (that is, provide energy or reserves) when needed by PJM to meet potential future reliability needs. Solidifying this "commitment" into a tangible and transactable product is accomplished through complementary capacity market design elements including:

a. Qualification and Accreditation: Establish eligibility and quantity available for sale.

b. Obligations: Define the responsibilities incumbent upon the seller.

c. Performance Incentives: Define consequences of both adequate and inadequate performance

7. In other words, the capacity product under the PJM framework necessitates a binding commitment to perform as and when required by PJM, especially during periods of stressed system conditions—times when there is a need for resource adequacy or there exists a risk of load shed. This commitment is subject to stipulated penalties for any instances of non-performance and is eligible for bonus credits in cases of over-performance.

8. Furthermore, the committed capacity must exist in a physical form, whether as an existing resource or one that meets the established criteria for a planned resource, and it must be deliverable to load. This commitment is measured and accredited in terms of Unforced Capacity ("UCAP") megawatts ("MW"), a metric designed to encapsulate a resource's anticipated performance during periods of load shed risk and to quantify its incremental contribution to system resource adequacy.

9. Moreover, the capacity product is substitutable; one megawatt of UCAP can be interchanged with any other megawatt of UCAP while preserving equivalent resource adequacy, as per established metrics. This interchangeability is maintained even across resource types with varying operational characteristics and limitations.

10. The following sections of this affidavit describe how the proposed changes to RPM serve to better align the market construct with supply-demand fundamentals for the capacity product outlined above to in service of the twin objectives of reliability and efficiency. These changes include:

a. Enhancements to the core analysis used to evaluate reliability risks,

b. A move to marginal accreditation, consistently using the enhanced risk model for all capacity 87resources,[1]

c. Changes to the Capacity Performance construct to incent performance, and

d. Changes to the market power mitigation framework to better align with the principles of competitive markets.

III. RISK MODELING ENHANCEMENTS

11. The core of PJM's proposal is a novel analytical framework for assessing the patterns, drivers, and probabilities of reliability risk. The proposed approach assesses resource adequacy under a broad range of potential system conditions, each representing one potential combination of weather, load and resource availability. This substantially enhances the accuracy of PJM's reliability risk assessment, enabling the identification and integration of incremental risks that inherently exist—present in the "ground truth"—but remained undetected under the status quo risk modeling framework.

12. **Hourly Granularity Analysis:** By leveraging historical data, PJM has created a robust model to estimate loss of load risk, duration and magnitude. PJM's approach examines resource adequacy at an hourly level. This granularity ensures that short-term fluctuations, which might be overlooked in a daily or monthly analysis, are captured. Such fluctuations can be critical, especially during peak demand hours or unexpected system stresses.

13. **Weather Outcomes Impacting Load and Resource Availability:** Weather plays a central role through its impact on both demand and supply. Extreme cold or hot conditions can lead to increased demand, while also impacting the availability or output of certain resources. PJM's proposed approach accounts for a wide spectrum of historically observed weather outcomes.

14. **Common-Mode Failure Analysis:** Beyond weather-related impacts, PJM proposes to adopt an innovative, non-parametric approach to also capture the impact of other (sometimes unobserved) drivers of common-mode failures. These are scenarios where multiple resources might become unavailable due to a shared vulnerability. By re-sampling from historical outage patterns, PJM's analysis can identify the extent to which these shared vulnerabilities have historically impacted class- and fleet-wide forced outages, and further identify the extent to which such outages have historically (and may in the future) drive elevated system risk.

15. As further discussed in the Affidavit of Dr. Rocha-Garrido, the result is a reliability risk model that better captures the likelihood, severity, and patterns of risk, including that of extreme event risk from correlated factors.[2] The proposed risk modeling framework aligns well with emerging best practices, and the overall

---

[1] Excluding Energy Efficiency Resources, as discussed further in section IV.

[2] Affidavit of Dr. Patricio Rocha-Garrido on Behalf of PJM Interconnection, L.L.C.,Docket No. ER24-___-000 (Oct. 13, 2023).

approach was well received by stakeholders in the PJM stakeholder process. Nearly every package sponsor put forward packages that rely on the PJM framework for enhanced risk modeling.

IV. MARGINAL ACCREDITATION USING ENHANCED RISK MODEL FOR ALL CAPACITY RESOURCES

16. Capacity accreditation quantifies the amount of capacity product a resource may offer into the capacity market. As discussed above, the capacity market and product continue to focus on resource adequacy and procurement of sufficient resources to satisfy the loss-of-load criterion. As such, capacity accreditation serves to capture a resource's contribution to resource adequacy, or expected ability to perform during times of system risk. Accreditation allows for a single, substitutable market product (i.e., accredited capacity. UCAP, or Accredited UCAP) to be used across resources with disparate operating characteristics, where one MW of the qualified product can be exchanged for any other MW of qualified product on the margin while maintaining equivalent resource adequacy outcomes

17. The main goal of PJM's proposed accreditation reforms is to improve accreditation to capture additional risk drivers and more accurately and equitably determine resources' relative contributions to resource adequacy.

18. These reforms occur against the backdrop of an evolving resource adequacy paradigm. Historically, the focus was primarily on planning for the (summer) peak given concentration of risk at that time. With the implementation of effective load carrying capability ("ELCC") for certain resources, PJM started down a path of fully recognizing resources differential contributions to reliability over time and across scenarios. Under the new paradigm, the focus is on identifying the least-cost, efficient portfolio of resources that—in aggregate—is expected to provide resource and energy adequacy in every hour of the year, across all potentially anticipatable scenarios, up to the target reliability metric.

19. PJM proposes two fundamental changes to capacity accreditation:

    a. **Modeling:** Incorporate enhanced risk modeling to directly assess resources relative contributions to resource adequacy, accounting for supply-side availability risks for all resource types.

    b. **Metric.** Accredit each resource "on the margin" to reflect its expected incremental contribution to system reliability during periods of risk.

IV.A ACCREDITATION MODELING ENHANCEMENTS

20. Under the status quo, there is no consistent application of a single accreditation methodology to all resource types. Thermal resources are accredited by de-rating the installed capacity ("ICAP") rating of the resource by a measure of the forced outage rate; intermittent and storage resources are accredited using a probabilistic model that does not directly use weather data, does not capture temperature- or other weather-dependent outage patterns, and does not capture "common mode" or other correlated outage drivers. And other resources are accredited using yet

other metrics designed to approximate their resource adequacy contribution, albeit approximations that were developed under a different understanding of the system's reliability risk drivers than we have today.

21. PJM proposes to directly leverage the enhanced analytical framework for risk assessment to consistently accredit all resources to reflect their assessed relative resource adequacy value. Capturing correlated outage drivers is crucially important for accurately assessing resource accreditation because system risk is higher when more resources are on outage, and by definition average resource performance is lower when more resources are on outage. If correlated outage drivers of any type increase the level of coincident resource outages and, consequently, of system risk, then any resource whose outages are correlated with those of other resources contributes less to preserving system reliability *during the reliability events that are likely to occur.*

    a. **For thermal resources:** The proposed approach reflects the impact of temperature-dependent forced outages and de-rates, other non-temperature related correlated outages observed historically, and planned and maintenance outages (which are assumed to be distributed throughout the year so as to avoid periods of risk insofar as possible).

    b. **For Demand Resources:** The approach accounts for the coincidence between periods of risk and availability limitations, as well as the variable load reduction available from the demand response as system load varies over the year while resources' firm service levels remain constant.

    c. **For Intermittent Resources and storage:** While these resource types are today accredited using an ELCC model, the enhanced accreditation methodology proposed will reflect different patterns of risks, changing risk weighting, and interactions between these resources and all other resources now modeled comprehensively.

22. PJM proposes to exclude Energy Efficiency Resources from the enhanced modeling and continue to assess their value, as under status quo, based on post-installation and measurement and verification reporting, which estimate the impact of energy efficiency measures on peak loads. Because the impact of energy efficiency is largely already included in the PJM load forecast models, it would be inappropriate to include such resources against the system risk and accreditation analysis, which would require further reducing forecasted hourly loads. Doing so would double-count the impact of energy efficiency, impact modeled system risk patterns in a counterfactual manner, change PJM's assessment of risk patterns, and distort the assessed capacity value of all other modeled resources.

IV.B MARGINAL ACCREDITATION

23. Marginal accreditation is a metric that reflects, for a given system, **the expected incremental reliability contribution** of each resource. Marginal reliability values can be extracted from the probabilistic risk analysis of a resource's contribution to avoiding load shed in the model. The reliability contribution of a resource is most naturally observed as a change in the reliability metric when the resource is added;

using the EUE metric, it is the change in system EUE caused by adding the resource. This EUE-denominated contribution can be translated to MW by comparing the EUE impact of the resource in question to the EUE impact of a hypothetical "perfect" resource. A resource that reduces EUE by X times as much as the level of reduction in EUE from 1 MW of perfect always-available capacity thus receives a translated value of X MW of accredited value.

24. The principle of marginal-value compensation is fundamental to the design of efficient wholesale markets. This principle underlies all key market products, including energy (locational marginal prices) and reserves. The core design of the capacity market supply-demand clearing mechanism also embodies marginal pricing, where the price allocated to all cleared capacity resources in a specific transmission-constrained area equals the marginal value of the last MW of capacity cleared in that area. Marginal accreditation aligns coherently with the established marginal pricing approach prevalent in the capacity market and indeed all PJM wholesale markets. As described by Potomac Economics, "[i]n competitive markets, the debate between total/average value and marginal value never arises because competitive markets always value products at their marginal value."[3]

25. Beyond aligning with the principles underlying all wholesale markets in PJM, accrediting capacity to reflect its expected incremental impact on has substantial benefits over alternatives. I briefly describe these here, and provide numerical examples in an appendix to my affidavit.

26. **Encourages cost-effective investment and retirement of resources.** Adopting a marginal approach to capacity accreditation fosters an environment where resource owners are incentivized to make economically rational decisions. Specifically, it drives investment into resources that offer the greatest reliability per dollar and steers away from resources that are more costly for the incremental reliability they provide. Moreover, it signals the retirement of less efficient resources whose energy, ancillary services, capacity, and other market and non-market value is less than their operational, maintenance, and amortized costs of necessary investments. As a result, resources that remain on the grid are those that best balance cost and reliability.

27. **Aligns the accredited value with expected performance during high-risk hours in operations**, which is necessarily on the margin. In operational terms, the most valuable resources are those that are available during times of highest stress or demand on the system – typically during high-risk hours. Marginal accreditation ensures that the capacity value assigned to resources directly corresponds with their expected performance during these critical periods. This approach recognizes and appropriately compensates resources for their true value during periods of expected operational risk.

28. **Yields a reliability-neutral exchange rate** and allows for a substitutable product definition where accredited capacity can be exchanged on the margin with no

[3] Comments of Potomac Economics, Docket No. ER22-772-000, at 13 (Feb. 11, 2022).

expected change in reliability. Marginal accreditation establishes a framework where capacity resources are interchangeable or substitutable as they offer equivalent reliability contributions per accredited unit of capacity. This means that when one unit of accredited capacity is exchanged for another on the margin, the overall reliability of the system remains unchanged. This enhances reliability by mitigating the reliability impact of imperfect forecasting of the resource mix, as small changes from the assumed mix yield nearly equivalent reliability at the same total accredited MW level.

29. **Naturally reflects interactions between resource types in accreditation values.** A marginal accreditation approach inherently accounts for interactions across traditional thermal, renewable, storage, and other resources. When accrediting capacity, this method does not view each resource class in isolation but considers their value in the context of the broader system, leading to more accurate and representative accreditation values. A marginal accreditation approach recognizes how the demographics of the fleet influence overall system risk and how that impacts the accreditation of each resource.

30. **Captures synergies and diminishing reliability value among resources** without a need to allocate diversity benefits to classes. As the mix of resources on the grid changes, certain combinations of resources can lead to synergistic reliability benefits. Conversely, as the penetration of a particular resource type increases, its incremental reliability value might diminish. Marginal accreditation naturally captures these dynamics, ensuring that capacity values remain representative of each resource's actual contribution. This eliminates the need for arbitrary allocation of diversity benefits to specific resource classes, simplifying the accreditation process and increasing the level of objectivity and fairness in treatment across resource types.

31. Potomac Economics, the NYISO Market Monitoring Unit, summarized the benefits as follows in the FERC proceeding regarding marginal accreditation in NYISO:

> A marginal approach will pay resources based on their expected availability at times when reliability is most threatened. Marginal capacity values will naturally change over time as the resource mix and needs of the system change. This will appropriately align capacity payments with the incremental reliability impact that an investment or retirement decision would have on the system. Marginal capacity payments provide signals to invest in the most efficient mix of clean energy resources, build or maintain additional resources that are needed for reliability, and retire the surplus generators that provide the least reliability benefit.[4]

[4] Motion to Intervene and Comments of Potomac Economics, Docket No. ER22-772-000, at 3 (Jan. 26, 2022).

IV.C ANALYSIS OF BENEFITS OF ENHANCED RISK MODELING AND ACCREDITATION

32. I conducted simulation analysis to compare potential clearing results under the status quo Base Residual Auction design with those under the proposed capacity market with risk modeling and accreditation enhancements. The analysis analytically demonstrates, for one potential set of market conditions, as recently observed, the reliability and efficiency benefits expected from the PJM proposal on risk modeling and accreditation. I briefly summarize the framework and results of this analysis here, and provide additional details regarding the modeling framework and assumptions in an appendix to this affidavit.

33. From the most recent Base Residual Auction, conducted for the 2024/2025 delivery year, I used offers, load forecasts, and an assumed resource mix (for risk modeling). For the status quo case, I removed LDA internal capacity and Capacity Emergency Transfer Limit constraints and re-cleared the auction to yield an "unconstrained" RTO price. This maximized comparability with other cases given that not all LDA requirement levels had yet been assessed at the time of analysis. I incorporated updated resource accreditation consistent with the changes proposed, and translated offers to maintain the same total cost in dollars that were actually observed for each 2024/25 offer or offer segment. For example, suppose an 8 MW UCAP resource offered at $50/MW-day, reflecting costs of $400/day; if under the proposed changes the resource is now accredited at 5 MW UCAP, I updated the offer to $80/MW-day corresponding to the same $400/day total resource cost. I also updated the reliability requirement and Variable Resource Requirement ("VRR") curve, and re-cleared the auction.

34. For context, the 2024/2025 Base Residual Auction actual clearing quantity was 139,810 UCAP MW at a price of $28.92/MW-day. In this analysis under the "unconstrained" (no LDA constraint) status quo base case, the cleared quantity was 139,145 UCAP MW at $43.33/MW-day. This corresponds to a 15 percent reserve margin (that is, UCAP MW cleared relative to 50/50 summer peak load), which under the status quo risk modeling was believed to correspond to roughly a 1 in 100 LOLE and 75 MWh EUE. However, when I assess the cleared results from that status quo base case using the enhanced risk analysis as proposed, it reveals substantially lower reliability: roughly 1 in 40 LOLE and 350 MWh EUE (that is, over four times as much expected unserved energy as previously believed).

35. I then reran the 2024/2025 Base Residual Auction using the proposed enhancements to risk modeling and accreditation. The impact is such that the auction results clear a different set of resources and improve reliability to 1 in 50 LOLE and 260 MWh EUE, a 25 percent improvement in EUE relative to the status quo case. This outcome is the result of the combined effect of several moving pieces. Some resources have higher accreditation under the enhanced modeling than under status quo; these offer more UCAP megawatts at lower prices. Others (most) receive lower accreditation than before, and offer less UCAP megawatts at higher prices. Even before considering changes to the reliability requirement and VRR curve, these two effects in combination yield beneficial swapping of cleared and uncleared resources on the margin, yielding a more reliable cleared resource

mix. In addition, changes in the forecast pool requirement (driven by changes in risk modeling) and in Net CONE (driven by changes in the accreditation of the reference technology) shift the VRR curve upwards and to the left. This causes the market to be relatively less tight than without the demand adjustment, though in combination with the aggregate reductions in accreditation, there is an overall tighter supply-demand balance than under the status quo.

36. Total costs to consumers increase modestly from $2.2 billion in the status quo case to $2.4 billion in the enhanced design case. Further, the total supply cost (that is, total offered cost of cleared resources, equivalent to production costs in the energy market) actually *falls*, from $330 million to $310 million. These results suggest that the risk modeling and accreditation enhancements allow for more efficient clearing outcomes, improving reliability (25% decrease in EUE) at moderate customer costs (10% increase) and slight savings (5% decrease) in overall system-wide costs of supply by enabling PJM to identify and procure the low-hanging fruit of reliability beyond the margin. I believe this is a reasonable representation of the potential benefits of the proposed approach under relatively over-supplied capacity market conditions such as those that persisted in PJM in the early 2020s.

37. To investigate the potential impacts of the proposed changes under relatively tighter system conditions, I compared the outcomes under status quo to those under the PJM proposal under alternative, synthetic, assumptions of the supply/demand balance. In particular, I adjusted supply offers from the 2024/25 auction by scaling all UCAP quantities offered at a zero price by 90%, thereby contracting the supply curve. This yielded RTO clearing prices of $86.13/MW-day under the status quo case and $114.17/MW-day under the alternative case. I assessed the reliability outcomes and found that the cleared resources under the status quo case were expected to yield substantially worse reliability outcomes of 940 MWh EUE compared to 400 MWh EUE under the enhanced design case. In other words, the proposed design reduced unserved energy by nearly 60 percent when under tighter supply/demand conditions. Customer costs increased less than 20 percent, from $4.3 billion in the status quo case to $5.1 billion in the enhanced design case, while the total supply cost of cleared resources again fell slightly, from $500 million to $490 million. These results are consistent with those of other similar scenarios I tested (with different assumptions regarding the contraction of the supply curve) and indicate that the proposed design enhancements could substantially improve efficiency in clearing outcomes when the system is tight.

38. The analysis described above is indicative of the impact the proposed changes are expected to have on auction results under a range of system conditions, but it captures only a portion of the expected benefits of the proposal. This is because the analysis thus far has focused only on comparing outcomes for a single auction and a single delivery year, holding offered costs constant. This illustrates what may be termed the "short-run" benefits of the proposed changes. In the "longer-run," the proposal will also induce changes in exit, entry, and other investment behavior consistent with market participants maximizing profits under a different market regime. These effects, not captured here, will change participant offer behavior and levels, because the competitive offer level in one year depends on discounted future revenues, which are different under different accreditation levels

and auction outcomes. These “longer-run” changes would tend to magnify the reliability and efficiency benefits expected in the short term that are demonstrated in the indicative analysis above.

V. CAPACITY PERFORMANCE CONSTRUCT

39. PJM continues to believe in the importance of in-year, operational, event-based performance assessments to incentivize performance of committed capacity resources and re-allocate capacity revenues from relatively poor performing resources to relatively high performing resources, as the Capacity Performance construct does today. The proposed changes to the performance assessment framework aim to refine, not violently disturb, the Capacity Performance construct.

40. Before discussing those changes, it is valuable to place the Capacity Performance construct in the context of the overall RPM performance assessment and testing framework designed to help ensure delivery of the capacity that has been committed through forward auctions.

    a. **Generator Seasonal Rating Tests**. Assesses resources’ ability to operate at committed ICAP in both summer and winter seasons. Relative to the status quo, PJM proposes to require physical demonstration of capability in each season, and remove excusals for inability to test to committed ICAP in each season. As today, a daily commitment deficiency penalty would be assessed for resources that have insufficient UCAP. The Daily Deficiency Rate set at the applicable clearing price ($/MW-day) for the resource plus the greater of $20/MW-day and 20% of clearing price.

    b. **Generator Operational Testing.** Allows PJM-initiated testing of generators’ availability status to better ensure they are capable of operating if and when needed for reliability, up to twice in each season (summer and winter), excluding re-tests following a failed test.

    c. **Capacity Performance Assessment Intervals.** Enhanced assessment of performance during times of highest system reliability risk.

41. Returning to the Capacity Performance construct, there exists a tension across three natural design criteria for performance assessments, requiring compromise across them: (a) the value of sufficiently strong incentives, (b) the value of assessments focused on hours of risk, and (c) the value of limiting risk of atypical under-performance.

42. The primary components of the Capacity Performance framework include the elements below. The design enhancements PJM proposes to these elements aim to strike a different balance across those competing design criteria.

    a. Definition of a Performance Assessment Interval (“PAI”),

    b. Non-Performance Charge and bonus rate,

    c. Stop-loss, i.e., maximum penalty for an under-performing resource,

    d. Assessed resources, i.e., resources that are eligible for penalty and bonus,

e. Balancing Ratio, i.e., the threshold between penalty and bonus, and

f. Rules regarding performance excusals.

V.A DEFINITION OF A PAI

43. A PAI occurs when certain system conditions are met. PJM recently filed and the Commission accepted a change to remove certain existing triggers (e.g., deployment of pre-emergency Demand Resource) and more narrowly focus on a set of triggers that reflect times of greater reliability risk. PJM does not propose further changes on this element.

44. Focusing the timing of assessments on hours of highest reliability risk aligns the financial risks with the periods for which we procure capacity—during system stress events. This alignment ensures consistent incentives for real-time performance and fosters prudent investments, maintenance, and preparations to mitigate risk and enhance performance. Further, this timing aligns with the fundamental definition of capacity in the PJM design, which is focused on hours of operational risk. Any divergence in the value of real-time capacity product from hours of risk would misalign incentives, creating a disparity between resources' accredited value, which is aligned with performance during hours of risk in our marginal accreditation concept, and the different incentive introduced by the performance assessment.

45. For example, consider a 100 MW ICAP resource accredited at 10 MW UCAP due to high correlation of its outages with other resources' outages and elevated risk. Such accreditation enables the resource to receive compensation commensurate with their expected contribution to resource adequacy, equivalent to 10 MW of perfect, always available capacity. Suppose the resource is expected to perform substantially better during performance assessment intervals under an alternative, broader definition of Performance Assessment Interval triggers, such that its average availability and performance during the broader definition equals 20 MW. Even though the additional performance during non-emergency assessed intervals does not improve system resource adequacy, the resource would expect to receive Capacity Performance bonus revenues for performing above committed UCAP. This re-distribution of capacity revenues works against and partially reverses the benefits of the proposed accreditation changes and harms incentives to invest in enhancing performance during the system conditions most strongly associated with loss of load risk.

V.B NON-PERFORMANCE CHARGE AND BONUS RATE

46. The Non-Performance Charge rate is the $/MWh rate paid by resources that underperform and allocated to resources that over-perform. Currently the Non-Performance Charge rate is proportional to the Net Cost of New Entry (Net CONE) and is today (in the 2023/2024 Delivery Year) approximately equal to $3,350/MWh; PJM does not propose to change the rate. This retains the relatively high penalty rate for resources that fail to perform during the hours of greatest reliability risk. As discussed above, this provides strong incentives in both the

forward time frame (e.g., for investment decision) and in the operational time frame (e.g., for fuel purchase and other operational decisions).

47. The bonus rate calculation is determined by the ratio of the total amount of charges collected by under-performers divided by the total MWh of over-performance. PJM has proposed and most package sponsors adopted a small modification to better equalize the penalty and bonus rates, such that an MWh of under- or over-performance is more nearly equally valued during PAIs (further discussed below in section V.E).

V.C NON-PERFORMANCE CHARGE STOP-LOSS

48. The stop-loss is the maximum amount of Non-Performance Charges, in dollars, that a resource can accrue in a given Delivery Year. This provision is in place to ensure that Non-Performance Charges to a Capacity Resource are bounded. Currently the stop-loss is set based incurring Non-Performance Charges up to a level of 1.5*Net CONE*Committed Capacity*365 (1.5x Net CONE in shorthand). PJM proposes to reduce the stop-loss to 1.5 x applicable Base Residual Auction clearing price. For clarity, the stop-loss applies to the total gross Non-Performance Charges incurred by individual resources and would not imply any RTO-wide limitation on the number of PAIs.

49. The primary driver of this change was to reduce the tail-end risk of the most extreme Non-Performance Charges that could harm the investability of the PJM markets. An assessment and incentive structure with a high Non-Performance Charge rate and a high stop-loss places substantial idiosyncratic risk on Capacity Market Sellers. Given the relatively low number of PAIs, the Law of Large Numbers does not guarantee that any given resource's average observed performance matches their long-term average or capability. Thus, a resource with high underlying, natural, "expected" performance may nevertheless face substantial penalties. This risk, borne by Capacity Market Sellers, imposes real societal costs, and reasonably would be expected to be reflected in sellers' offers; ultimately, the cost of the risk may be borne partially or substantially by consumers. In other words, the potential, however unlikely, for a Capacity Market Seller to lose multiple years of capacity revenues for non-performance in a single event may deter future investments in PJM's markets, ultimately undermining the competition that the capacity market needs to meet the twin objectives of reliability and efficiency.

50. Reducing the stop-loss should not have a significant impact on the overall incentives provided by the Capacity Performance construct, for two reasons. First, the changes to the accreditation methodology substantially improve the alignment between resources' accredited levels and the level of expected performance during PAIs. Enhancements in the resource testing framework further mitigates the risk of systematic underperformance. Thus, risk that a resource is systematically over-accredited is substantially mitigated. This increases the probability that resources will perform at or near expectation during capacity emergencies reduces the likelihood of exceeding the stop-loss.

51. Second, the recently approved change in the PAI definition and triggers in Summer 2023 has focused PAIs on only the most extreme circumstances such that under the prior and current definition, the new definition is likely to produce less PAI. As an example of the impact of this change, PJM has conducted an analysis of the potential and likely future impact of the recent PAI trigger changes during Winter Storm Elliott. Between the 23rd and 24th of December, 2022, there were a total of 277 five-minute intervals (23 hours) that met the definition of a PAI under the previous PAI definition, which prevailed at that time. Only 73 intervals (6 hours) of the Winter Storm Elliott events would have been PAIs under PJM's current RAA/Tariff rules.

52. Even during Winter Storm Elliott no resource met the stop-loss, nor would have met the stop-loss under the proposed rules given the applicable BRA price. Thus, this change would likely have little impact on the operational or investment incentives associated with a future potential event of the magnitude of Winter Storm Elliott.

V.D ASSESSED RESOURCES

53. Under current rules, any resource or transaction that out-performs its committed level during a PAI is eligible for a bonus credit. This can include energy-only resources, partially committed capacity resources, and import transactions from neighboring regions. PJM proposes to instead limit the pool of resources that are assessed during PAIs to only committed capacity, such that resources must meet the capacity qualification criteria and accept the obligations associated with a commitment to be eligible to receive any capacity revenues, including capacity PAI bonus revenues.

54. Under this proposal, resources would be eligible to receive bonus payments for performing up to committed ICAP if such performance exceeds the level of performance expected of them, given the balancing ratio (discussed in a later sub-section below). Non-committed capacity resources, non-capacity resources, and imports not associated with committed pseudo-tied external resource would not be eligible for bonus.

55. This change further clarifies the differences between the capacity product and the energy product. As described at the start of this affidavit, the capacity product is a *commitment* to perform, around which PJM can plan for the reliable operation of the system. The capacity product requires that the resource's output be assessed as deliverable to load, and that such deliverability is supported by Capacity Interconnection Rights. The capacity product implies a commitment to compliance with a number of testing requirements to ensure that the resource is ready and capable of performance when needed by PJM, to the extent it is possible to do so under the conditions that occur in the delivery year. And the capacity product carries with it an obligation to offer into the wholesale energy and ancillary services markets. None of these requirements apply to energy-only resources, and only some apply to non-committed capacity resources.

56. In short: a resource that has not sold the capacity product, has not taken on a capacity obligation, and has not met all requirements associated with that is not

providing the capacity product by simply providing energy during a performance assessment interval. Under the revised capacity performance framework and other capacity product definition changes, capacity performance is no longer intended to be a replacement or substitute for sufficiently robust energy & ancillary services prices. It is not clear why the incentives for performance for non-capacity resources must or should come from the capacity market. In fact, these incentives are much more naturally found in the energy & ancillary services markets.

57. Ultimately the status quo capacity performance framework effectuates a re-distribution of capacity revenues, including to resources that would never qualify to participate in the PJM capacity market. Non-capacity resources can, in expectation, earn capacity revenues even though they would never qualify to offer the capacity product or receive a capacity commitment. This also applies to resources that could qualify but chose not to participate, as well as to resources that did participate in the capacity market but *through their offer level indicated an unwillingness to accept a capacity obligation at the prevailing price.* The proposed change seeks to provide a more consistent definition to the capacity product, and the compensation for that product, by limiting *capacity* revenues to just those resources that meet the qualification criteria to be capacity and have been committed as capacity in the market.

58. Furthermore, relative to the status quo, this proposal reduces the capacity revenues transferred to non-committed and non-capacity resources during PAIs, making it relatively more attractive to accept a capacity commitment and the corresponding obligations. Because there is no expectation of bonus revenue for uncommitted capacity, there is no foregone bonus revenue when a resource takes on a commitment. In other words, the opportunity cost associated with bonus payments associated with Capacity Performance for selling capacity is eliminated under the proposed design. This will incent resources to more readily offer capacity in the forward auctions and provide the forward, planning value that committed capacity resources bring to the system and that uncommitted resources may not. This also recognizes the difference in value provided by a committed capacity resource that takes on testing obligations and energy must offer obligations compared to an energy-only resource that does not have these additional requirements.

59. There are a few additional impacts that naturally result from the proposed change in assessed resources during PAIs that are worth noting. First, the incentive to perform for non-committed capacity and energy-only resources, as well as energy-only imports, is directionally lower during PAIs when they are not eligible to receive a portion of capacity revenues during PAIs. Nonetheless, this proposed change to limit the pool of capacity compensation to committed capacity resources is reasonable for the reasons provided above, and the appropriate market price for those resources providing energy or ancillary services at the time of a PAI, but that have not been cleared or committed as capacity, is the relevant prices in the energy and ancillary services markets, with which the incentive provided by high energy prices during triggered PAIs (i.e. reserve shortages) is not negligible.

60. In addition, the proposed change renders Demand Resource and Price Responsive Demand ineligible for bonus payments, as the Expected Performance of those

resource types during PAIs is set at the committed ICAP level of the resources, which implicitly limits the performance considered in the assessment to no more than the amount that's expected to perform. Notwithstanding, the netting of performance across underlying customers, registrations, and resources that are dispatched during a PAI is still allowed, such that the "over-performance" of any dispatched Demand Resource can still be used to offset the under-performance on another resource in the CSP's account during a PAI. This appears to be a reasonable and non-discriminatory outcome. There are two ways that Demand Resource (or any resource) could be eligible for a bonus payment under the status quo Capacity Performance design: (1) performance of uncommitted capacity, and (2) performance of committed capacity at committed level when the balancing ratio is below unity.

61. Regarding the first point, bonus compensation for performance of uncommitted capacity is being eliminated for all resources. A Demand Resource only commits to reducing load to the Firm Service Level ("FSL") and is accredited for the value of this reduction. Any reduction below FSL would be uncommitted capacity as the underlying load did not accept a capacity commitment for such additional curtailment.

62. Regarding the second point, under the status quo, Demand Resources and Price Responsive Demand are already ineligible for bonus compensation for performance above balancing ratio. "Expected Performance," or the level against which performance is assessed for the purposes of PAI settlements, is set at ICAP (rather than UCAP * Balancing Ratio) and PJM does not propose to change this. The rationale for this design choice is that the commitment that Demand Resources take on is to reduce load to the FSL, not, like Generation Capacity Resources, to provide output up to a certain level. The expected resource adequacy value of such reduction to FSL is assessed in the accreditation and risk analysis, where the load available to curtail is modeled as scaling proportionally with the level of system load. The balancing ratio falling below one during a Performance Assessment Interval corresponds to an event when system load was below the total amount of capacity procured. Because Demand Resource load is modeled as scaling proportionally with system load, the load underlying the Demand Resource would be expected to naturally fall below such load's peak load contribution during the event. When such a resource curtails load to FSL, the amount of curtailment value actually provided is not equal to UCAP but rather is expected to equal UCAP times the balancing ratio. Thus, because the Demand Resource is providing value exactly equal to that which was assumed during accreditation, there is no over-performance to compensate.

63. Energy Efficiency Resources are also ineligible for bonus compensation under the proposed design. This element is a straightforward application of the proposed design. As there is no way to conduct in-year assessments of the value that Energy Efficiency Resources provided during performance events, there does not appear to be any basis to compensate for over-performance.

V.E BALANCING RATIO

64. The Balancing Ratio is used in determining the level of expected performance from committed generation during PAIs. It is intended to capture the amount of generation needed from committed resources to meet the system load during a PAI. For example, if system load during a PAI is at 120 GW and the total amount of committed generation on the system is 160 GW, the Balancing Ratio for the PAI would be set at 75%.

65. PJM proposes straightforward modifications to the Balancing Ratio formula to reflect the proposed changes to assessed resources and to adjust for excused MW, better balancing the penalty rate and bonus rate during PAIs.

    a. Balancing Ratio Numerator = Total Committed Generation Capacity Resource's Actual Performance (capped at the committed ICAP of each resource). No Net Energy Imports or Demand Resource/Price Responsive Demand Bonus MW.

    b. Balancing Ratio Denominator = Total Generation Committed UCAP (reduced for committed MW that are excused from the assessment)

66. These changes serve to reduce the potential differences between the Non-Performance Charge rate and bonus rate. Under the status quo calculation of the Balancing Ratio, a significant disparity can be introduced because the Balancing Ratio is invariant to the amount of excused resources. For example, suppose the Balancing Ratio was calculated under the status quo design. If one-quarter of the resources with Actual Performance below Expected Performance were excused, the total penalties collected would be reduced by roughly one-quarter. This reduces the available bonus pool to be distributed across resources with Actual Performance above Expected Performance. Thus, the bonus rate would be reduced by roughly one-quarter.

67. The proposed change has at least two benefits. First, improving the symmetry between Bonus and Penalty rates better aligns the marginal incentives of committed capacity resources that over-perform compared to those that under-perform during a PAI. Second, it better allows market participants with over-performing resources to use the bonus revenues collected for such over-performance to net against non-performance charges on a MW-for-MW basis.

V.F RULES REGARDING PERFORMANCE EXCUSALS.

68. The current rules regarding when a resource with a capacity commitment may be excused from performance during a PAI lack clarity on certain specific operational circumstances. The changes PJM proposes are primarily clarifying changes regarding the limited cases in which offline resources are excused. Recent experience administering the Non-Performance Charges following Winter Storm Elliott confirmed earlier concerns regarding the urgent need for clarification.

69. The tariff language describing excusals is now clear that offline resources shall not be excused except when on planned or maintenance outages previously approved by PJM and when given direct manual dispatch instructions to turn or remain

offline. Online resources, if underperforming, may only be excused for partial planned and maintenance outages previously approved and reductions in output due to transmission system limitations communicated via manual dispatch instructions or security-constrained economic dispatch ("SCED").[5]

V.G ADDITIONAL CAPACITY PERFORMANCE REFORMS

70. PJM proposes two additional Capacity Performance-related changes which I discuss in this section: first, to remove the option for Fixed Resource Requirement ("FRR") Entities to elect a physical penalty assessment and instead apply the same financial assessment to all committed capacity; and second, to enable more granular transactions of the PAI obligations associated with committed UCAP.

71. Under the status quo Capacity Performance design, FRR Entities are provided the choice of either a physical or financial penalty assessment in the event of non-performance of resources in their portfolio. The physical penalty assessment requires non-performing entities to provide additional, "physical" capacity in the following delivery year as compensation for their non-performance. However, maintaining two distinct penalty mechanisms could lead to inequities in treatment for differently situated market participants and may ultimately under-incentivize performance during PAIs by FRR Entities. PJM is thus proposing to move to a singular, financial penalty assessment for all market participants. This approach:

   a. **Reduces inequities in treatment.** Different penalty mechanisms can lead to disparities in how similarly situated market participants are treated. For instance, two entities with similar under-performance could face substantially different consequences, one more severe than the other, simply based on their choice of penalty mechanism. This can result in perceived or actual unfairness, undermining trust in the market's ability to effectuate equitable outcomes.

   b. **Ensures strong and consistent incentives for performance during PAIs.** The financial incentives associated with PAIs are set at high levels to reflect the genuinely high potential costs of non-performance during periods of heightened risk. When an FRR Entity that has elected the physical penalty underperforms, its subsequent commitment to bring additional capacity in the following delivery year does not adequately compensate the system or other PJM participants for the risk caused by this under-performance. This is fundamentally because capacity is not interchangeable or fungible across different Delivery Years. More specifically, having an excess of committed capacity in one Delivery Year, when the amount of reliability risk is uncertain, likely does not provide the same level of system reliability as what was compromised by falling short by an equivalent quantity during an actual operational risk event. As such, the emphasis on the importance of

[5] For clarity, online units are excused if LMP-desired (that is, the level of output that would be economic based on a resource's dispatched schedule, absent ramp constraints) falls below the expected performance level.

> an FRR Entity fulfilling its capacity commitments during these crucial operational events within the specified Delivery Year cannot be understated. The penalties and incentives must be sufficiently robust to ensure that the committed capacity is available when it's most needed.

72. PJM proposes to introduce a new mechanism that allows Capacity Market Sellers to exchange the PAI obligation associated with committed UCAP at up to interval-level granularity. The primary motivation for this proposed mechanism is to enable Capacity Market Sellers to more effectively manage Capacity Performance risk and to provide for greater opportunity for the financial PAI obligation to be backed by a physical hedge.

73. By allowing for more granular transfers of the PAI obligations associated with committed UCAP, Capacity Market Sellers are granted increased flexibility to adjust their positions and manage their exposure to Capacity Performance risk in response to both unexpected and expected events. Capacity Market Sellers can mitigate their exposure to Capacity Performance risk by reacting promptly to unforeseen changes in their expected availability, such as when they face a higher probability of forced outages, and transacting the PAI obligation with a different market participant who is available and able to essentially offer insurance against under-performance during potential PAIs.

74. The ability to transfer PAI obligations on a granular basis also provides Capacity Market Sellers with a broader array of opportunities to hedge their positions. In the existing framework, there often exists a mismatch between static UCAP-based financial obligations and a resource's expected physical availability. This discrepancy is particularly acute for intermittent resources with diurnal patterns but also applies to resources whose probability of availability may vary in more complex ways depending on weather patterns and other system conditions. With the proposed changes, Capacity Market Sellers can more closely match their financial obligations with the expected availability of their physical resources. This alignment both reduces individual participants' Capacity Performance risk and also helps to ensure that there is a physical backing for financial commitments, enhancing the system's reliability and robustness. Having a physical hedge means that the system can count on actual energy or capacity being available when required, reducing the risk of shortages or reliability issue. Furthermore, this alignment means that Capacity Market Sellers may be able to reduce their total exposure to uncertainty in Capacity Performance bonus revenues and Non-Performance Charges, thus reducing their overall Capacity Performance Quantitative Risk ("CPQR").

75. The following table summarizes the key elements of the proposed PAI obligation transfer.

Design Element	Existing Transfers and Replacements	Proposed PAI Obligation Transfer
Product	Committed UCAP	PAI Obligations of Committed UCAP
Maximum Obligation	Owned UCAP	Lesser of owned ICAP and CIRs
Locational Constraints	Recognizes LDA constraints	Status quo rules on replacements
PAI Impact	Adjusts committed MW in PAI shortfall calculation for all intervals in day	Adjusts committed MW in PAI shortfall calculation for applicable intervals
Other Impacts	Impacts other obligations (e.g. energy market must offer, testing requirements)	No impact beyond PAIs
Indemnification	Seller indemnifies PJM if buyer can't pay	Seller indemnifies PJM if buyer can't pay

VI. MARKET POWER MITIGATION AND MARKET SELLER OFFER CAP

76. The fundamental objective of market power mitigation in the capacity market is to return the capacity market to outcomes that would prevail in a competitive market: one with prices reflecting marginal value and the marginal economic costs of competitive market participants. Accomplishing this objective requires mitigation of uncompetitive offers to competitive levels. For each Capacity Resource offered into the capacity market, the competitive offer level is the expected profit-maximizing offer for a competitive Capacity Market Seller—that is, one that does not have the incentive and ability to affect market prices through their offer quantities and/or levels. Ultimately, the competitive offer level is the price below which the costs of accepting a capacity obligation exceed the benefits (net profits) from doing so, and below which a competitive seller would prefer not to clear.

77. Economic theory reveals that a competitive Capacity Market Seller's profit-maximizing offer is equal to their economic costs of offering the resource into the capacity market, accepting the capacity commitment, and complying with all relevant obligations of a Capacity Resource. Thus, the competitive offer level must necessarily reflect all economic costs of the resource. Those economic costs include all costs that a competitive Capacity Market Seller would consider when making an offer.

78. Economic costs for a competitive seller are *going-forward net avoidable costs*:

a. *going-forward*: costs that have not yet been incurred; costs that are not sunk;

b. *net*: costs net of revenues that are enabled by choosing to experience the costs; and

c. *avoidable*: costs that can be avoided if not supplying the good/service.

79. Thus, the relevant costs that a competitive Capacity Market Seller would wish to represent in a capacity offer are any and all costs that have not yet been incurred and could be avoided by not selling capacity, net of any revenues that are enabled by the Capacity Market Seller choosing to incur the costs and sell capacity.

80. There are two scenarios under which these relevant costs would substantially differ. The first scenario is that of a Capacity Market Seller who receives insufficient revenues from the energy and ancillary services markets (the "E&AS Offset") alone to justify the continued profitable operation of a resource. Such a Capacity Market Seller would rationally plan to retire or mothball their resource if they receive insufficient capacity market revenues to support continued operation. A competitive offer for such a Capacity Resource would reflect the full economic costs of selling capacity: the total gross going-forward avoidable costs of continuing to operate the resource rather than retiring or mothballing, net of the energy and ancillary services revenues that are enabled by the choice to continue operating the resource.

81. The second scenario is that of a Capacity Market Seller who does receive sufficient revenue from the energy and ancillary services markets to justify continued profitable operation of the resource, without additional capacity revenues. Such a resource is profitable and not at risk of mothball or retirement. However, a competitive Capacity Market Seller, given the choice, would not willingly accept a capacity obligation at any arbitrarily low price. Rather, they would choose to offer the capacity from such a resource according to the same economic framework outlined above: the offer would reflect economic costs, equal to going-forward net avoidable costs—only those costs that could and would be avoided by not selling capacity. Of the components currently included in the PJM Avoidable Cost Rate (ACR"), CPQR is clearly avoidable if not committed for capacity; all or parts of other ACR components may also be avoidable in certain circumstances (for example, a resource that incurs costs to arrange firm fuel that they would not incur absent a capacity obligation).

82. Thus, a Capacity Market Seller who plans to continue operating a profitable Capacity Resource regardless of their single-year revenues in the capacity market has economic costs at least as high as CPQR; it follows that the natural, profit-maximizing offer for such a Capacity Market Sellers and such a resource is at least as high as CPQR.

83. The PJM proposed changes to the Market Seller Offer Cap calculation follow this logic. Under the proposed design, Capacity Market Sellers would be enabled to reflect avoidable costs and foregone relative to those they would face given the unit's operating state if not cleared in the capacity market:

a. **Mothball/Retirement:** MSOC = Net ACR = Gross ACR – E&AS Offset, where avoidable costs in Gross ACR are determined relative to those incurred if the unit were to not operate for the year and mothball or retire, as applicable;

b. **Continue Operating:** MSOC = Gross ACR, where avoidable costs in Gross ACR only include the incremental costs of taking on a capacity obligation relative to continuing to operate and participating solely in E&AS markets (e.g., CPQR).

84. As an example of the issue with the current mitigation levels, consider a Capacity Market Seller with a gross avoidable cost rate of $50/MW-day, of which $10/MW-day is the CPQR component. Suppose this resource has a net E&AS offset of $60/MW-day. Under the status quo mitigation framework, the seller would be required to offer the capacity for this resource at $0/MW-day. However, the seller would prefer to not clear the capacity market unless they expect to receive more than $10/MW-day, offsetting the costs they *actually face* by selling capacity. In a competitive market, this seller would not offer less than $10/MW-day. Under the PJM proposal, the example seller would be able to offer the resource at their economic going-forward net avoidable costs, which are equal to the CPQR of $10/MW-day.

85. Certain objections raised to this proposal were raised during the stakeholder process. One such claim is that a resource expecting to receive excess profit in the E&AS market, sufficient to offset fixed and variable costs of continuing operation as a capacity resource, in fact do have net avoidable costs of zero. Such objections are not grounded in the economics of competitive markets. As described above, the purpose of the market power mitigation framework is to return the market to competitive outcomes. If the capacity market were a competitive market, no market power mitigation would be needed. In such a market a Capacity Market Seller facing non-zero CPQR or other going-forward avoidable costs would not offer to sell capacity below the level of those costs.

86. The capacity must-offer obligation imposed by the market power mitigation construct is *not* a must-clear or must-sell obligation. It is an obligation to offer as a competitive market participant would. Such a competitive participant would avoid CPQR by not selling capacity. Therefore, a competitive Capacity Market Seller should not be willing to accept a capacity obligation (and associated risk) for free, because they take on additional costs when selling capacity, compared to a baseline assumption of continuing operation without selling capacity. This is true even if the resource expects net profits in the E&AS market sufficient to offset their fixed and variable costs.

87. In summary: to accomplish the fundamental objective of market power mitigation—returning capacity market outcomes to those that would prevail in a competitive market—capacity offers cannot be mitigated below those levels equal to the natural, profit-maximizing offers of competitive Capacity Market Sellers. Such over-mitigation yields uneconomic outcomes. In order to avoid uneconomic over-mitigation, the Market Seller Offer Cap must reflect and allow all demonstrable net going-forward avoidable costs of selling capacity.

88. Indeed, this proposed approach is consistent with the formulation of bids in the ISO-NE Forward Capacity Market, where static delist bids (parallel to PJM capacity offers) are allowed above the dynamic delist bid threshold at the level of net going-forward costs, which are a function of going-forward costs minus energy and ancillary service market infra-marginal rent.

89. As described in ISO New England Inc. ("ISO-NE") training materials, going-forward costs are those "[c]osts reduced or avoided by not having a capacity supply obligation" and explicitly are "incremental costs" and "may be different if a resource is active versus inactive in energy markets."[6] In particular, if a "[p]articipant has negative outlook on market conditions during capacity commitment period," then the "[g]oing-forward cost (GFC) estimate includes all costs avoided from not participating in capacity, and energy and ancillary service markets" and "[i]nfra-marginal rents (IMR) are deducted from GFC estimate to account for portion of total avoided costs otherwise recovered through energy and ancillary service markets."[7] Alternatively, if a "[p]articipant has positive outlook of market conditions during CCP" then the "[g]oing-forward cost (GFC) estimate includes all costs avoided if resource were not participating in capacity market only" and "[c]osts incurred due to decision to remain in energy and ancillary service markets are excluded; infra-marginal rent (IMR) is set to zero."[8] The ISO-NE tariff further elaborates:

> GFC = annual going forward costs, in dollars. These are the expected costs and capital expenditures that might otherwise be avoided or not incurred if the resource were not subject to the obligations of a resource with a Capacity Supply Obligation during the Capacity Commitment Period (i.e., maintaining a constant condition of being ready to respond to commitment and dispatch orders). Costs that are not avoidable in a single Capacity Commitment Period and costs associated with the production of energy are not to be included. Service of debt is not a going forward cost. Staffing, maintenance, capital expenses, and other normal expenses that would be avoided only in the absence of a Capacity Supply Obligation may be included. Staffing, maintenance, capital expenses, and other normal expenses that would be avoided only if the resource were not participating in the energy and ancillary services markets may not be included, except in the case of a resource that has indicated in the submission of a Static De-List Bid that the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period.

---

[6] Ryan Hoskin, *FCM Delisting: Participant Training Webinar*, ISO New England, 23 (Feb. 9, 2023), https://www.iso-ne.com/static-assets/documents/2023/02/20230209-fcm-delisting.pdf ("FCM Delisting Webinar").

[7] FCM Delisting Webinar at 25.

[8] FCM Delisting Webinar at 26.

IMR = expected annual infra-marginal rents, in dollars. In the case of a resource that has indicated in the submission of a Static De-List Bid that the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period, this value shall be calculated by subtracting all submitted cost data representing the cumulative expected cost of production (total expenses related to the production of energy, e.g. fuel, actual consumables such as chemicals and water, and, if quantified, incremental labor and maintenance) from the Existing Generating Capacity Resource's total ISO market revenues. In the case of a resource that has indicated in the submission of a Static De-List Bid that the resource will be participating in the energy and ancillary services markets during the Capacity Commitment Period, this value shall be $0.00.[9]

90. Further, the ISO-NE approach allows for the inclusion of "risk premium" costs, including costs stemming from exposure to Pay-for-Performance charges. These costs would not be offset by infra-marginal rents when a resource plans to continue operating in the energy and ancillary services markets, as the value of the infra-marginal rent used in the determination of net going-forward costs is $0.00. The full delist bid formulation is provided in the ISO-NE training materials as follows:[10]

$$NGFC = \frac{[GFC - IMR] \times InfIndex + RP + CPP}{(CQ_{summer}, kW) \times (12, months)}$$

Where:

- **NGFC** is *net going-forward costs*
- **GFC** is *going-forward cost* including opportunity cost
- **IMR** is *infra-marginal rent*
- **InfIndex** is four-year expected inflation rate as published by the Cleveland Federal Reserve Bank
- **RP** is *risk premium*
- **CPP** is expected *capacity performance payments*
- **CQ_{summer}** is summer *qualified capacity*

91. In short, the proposed PJM approach is entirely consistent with ISO-NE's approved methodology today.

VI.A STANDARD CPQR APPROACH

92. PJM proposes to introduce a standard approach to estimate resource-specific CPQR based on assessment of resource-specific Capacity Performance risk given

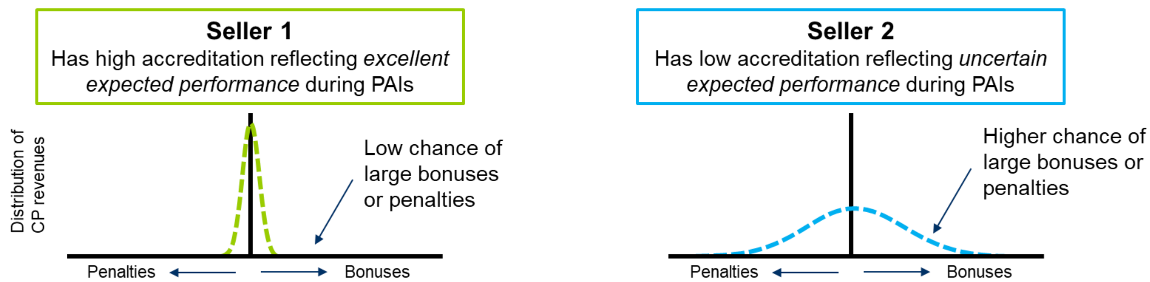
---

[9] ISO New England Inc. Transmission, Markets and Services Tariff, section III.13.1.2.3.2.1.2.A.

[10] FCM Delisting Webinar at 22.

historical performance. Such an approach would provide an acceptable starting point for CPQR that PJM will accept as reflective of the expected costs of a competitive participant to mitigate and manage the risks associated with a Capacity Performance obligation. It helps to improve transparency regarding the CPQR calculation for all market participants, including suppliers as well as load interests with cost concerns. In the remainder of this section I describe and provide rationale for the proposed approach.

93. CPQR is generally intended to reflect both expected net penalties and the cost of risk incurred by a risk-averse Market Participant from facing an uncertain distribution of delivery-year penalties and bonus revenues. Competitive Capacity Market Sellers naturally evaluate the capacity price at which they would be willing to accept capacity performance penalty risk. Suppose both of the following sellers envision a distribution of penalties and bonuses that on average cancel out such that the *expected value* of Capacity Performance bonus plus penalties is zero.



94. In this example, although there is no net bonus or penalty *on average,* neither seller should be willing to take on the risk for free nor could mitigate the risk for free. Both sellers would express a cost of accepting the risk in their offers, even if positive outcomes exactly offset negative outcomes *in expectation.* Seller 2 has a higher cost of risk (and cost of mitigating risk) and wishes to express higher offer price.

95. To implement the standard CPQR approach and reflect such differences across resources, PJM proposes an approach that is broadly consistent with the PJM Independent Market Monitor's simulation-based approach which reflects weather experienced during historical PAIs and condition probabilities (based on weather) for estimating the number of PAIs and unit outage probability.[11] In PJM's proposal, for each resource PJM would conduct a probabilistic analysis of unit-specific performance under a range of system conditions, using the same enhanced analytical framework used to study reliability risks and assess resource accreditation. This analysis would yield a distribution of performance during simulated PAIs, as well as other parameters (Balancing Ratio, etc.) necessary to assess the distribution of potential net Non-Performance Charges and bonuses.

---

[11] Joe Bowring & Siva Josyula, *CPQR Simulation Example*, PJM Interconnection, L.L.C. (June 10, 2022), https://www.pjm.com/-/media/committees-groups/task-forces/rastf/2022/20220613/item-03---cpqr-methodology-and-examples---imm.ashx ("CPQR Simulation").

96. The competitive cost of mitigating this quantified risk would then be assessed using a straightforward "value at risk" analysis. The standard CPQR would be calculated as the product of the extreme *value* at risk and the percentage *cost* of this risk:

Standard CPQR = Risk Cost × Extreme Value

97. In choosing a standard methodology for estimating CPQR, or the cost of managing the risk of Non-Performance Charges, there is not a singularly acceptable way to assess and value financial risk. The analytical approach selected by PJM for the standard CPQR methodology builds on one commonly used measure, the value at risk ("VaR"). This analytical approach estimates, using historical data or simulation-based analysis, the distribution of potential financial outcomes over a period of time, and then considers the potential exposure to financial losses at a pre-defined percentile level of that distribution. With respect to CPQR, PJM is proposing to use a probabilistic model, consistent with the one used for resource accreditation, to assess the distribution of potential annual net Non-Performance Charges that a resource may face in the Delivery Year, and then from that distribution, take the maximum exposure to Non-Performance Charges at a pre-defined confidence interval typically used in this VaR analysis, the 95th percentile. That risk exposure, which is generally intended to reflect an extreme value on the tail of the distribution, is then multiplied by an estimated cost of managing the risk to determine the CPQR value.

98. The probabilistic model used in the reliability risk analysis and accreditation of resources, or ELCC model, provides a robust and reasonable approach to assess the distribution of potential net Non-Performance Charges a resource may face in the Delivery Year as it already integrates many of the relevant factors that impact the calculation of net Non-Performance Charges. These factors include performance of the resource, which is simulated in the accreditation model under a broad range of system conditions and weather scenarios, the number and timing of modeled PAIs, which can be simulated in the model when the available supply falls below the load and reserve requirement in an hour, representing a reserve shortage and trigger for a PAI, as well as the parameters that feed into the Balancing Ratio and expected performance of resources to determine shortfall or bonus MW during the simulated PAIs. The other key factors that influence the calculation of net Non-Performance Charges that a resource may face in the Delivery Year are either known values, such as the Non-Performance Charge rate, or are values that will be estimated outside of the model and used as inputs to the probabilistic analysis, such as the annual stop-loss for the resource.

99. This approach is widely regarded as a prudent and methodologically sound practice within this context. Indeed, the ISO-NE internal market monitor "agrees that an industry-standard [VaR] approach is an acceptable framework for participants to manage and measure risk in the context of the Pay-for-Performance] capacity market" and further describes that "[VaR] and similar measures are widely used by financial institutions and businesses to measure risk

and determine whether action is needed to bring risks within acceptable corporate risk tolerances."[12]

100. Establishing the threshold at the 95th percentile is commonly accepted as a reasonable measure of a typical extreme value that is placed at risk (with some small probability) when facing the distribution of potential outcomes. This is consistent with application of the VaR methodology by the ISO-NE internal market monitor when designing a framework for "measuring and valuing risk that addresses resource-level specific risk factors under the Pay-for-Performance construct:"[13] "[t]he IMM applied the VAR approach by calculating the estimated loss at the 95th percentile of possible Capacity Scarcity Condition hours (H). In other words, the IMM set a one-in-twenty maximum acceptable net loss. However, rather than pricing the exposure dollar-for-dollar, the IMM placed a cost of risk for negative income at the chosen exposure level."[14] Furthermore, the 95th percentile was also used as an example of a reasonable choice of extreme value in the similar framework proposed by PJM Independent Market Monitor.[15]

101. The ultimate cost of mitigating or managing the Capacity Performance risk depends on the cost of reducing or hedging the maximum loss a participant is likely to incur once in 20 years (the 95th percentile loss identified above), that is, the cost of pursuing risk-management transactions including "entering financial hedges, acquiring insurance, or diversifying the participant's portfolio of risk assets."[16] The proposed VaR analysis uses an estimated cost of managing the extreme value risk reflecting a typical after-tax weighted average cost of capital ("ATWACC"). The ATWACC represents how much a company pays for capital, adjusted for taxes. It takes into account the cost of debt (interest rate), the cost of equity (expected equity returns), the company's debt-to-equity ratio, and the tax shield from interest payments on debt. It can also be thought of as representing the opportunity cost of capital for a firm, and is the minimum return that a company needs to generate on its investments to satisfy its investors (debt holders and equity holders).

102. Investors put their money in various assets with the expectation of a return. But all investments come with some level of risk. The riskier an investment is perceived to be, the higher the return investors will demand to compensate for that risk. This is known as the risk-return tradeoff. This impacts a company's cost of capital as follows:

---

[12] Informational Filing for Qualification in the Forward Capacity Market by ISO New England Inc., Docket No. ER15-328-000, Attachment B (Internal Market Monitor Review of De-list Bids for the Ninth Forward Capacity Auction: A Methodology Document), at 12 (Nov. 4, 2014) ("Internal Review").

[13] Internal Review at P 13.

[14] Internal Review at P 14.

[15] CPQR Simulation at 21.

[16] Internal Review at P 12.

a. The **cost of equity** is determined by the perceived riskiness of the company's equity shares. If investors perceive the company to be risky, they demand a higher return on equity, which in turn raises the WACC.

b. If the company is considered a credit risk (meaning there's a higher chance it might default on its debt), lenders will demand a higher interest rate, raising the **cost of debt** and thus the WACC.

c. If a company is heavily financed by more expensive equity (compared to cheaper debt), its **capital structure** leads to a higher WACC.

103. PJM today estimates a reasonable market default ATWACC for the purposes of estimating costs of the reference technology (for Net CONE) and the avoidable project investment recovery rate ("APIR") as a component of net avoidable cost rates ("net ACR"). While certainly not the only measure of the potential costs of the risk-mitigation transactions to lower the one-in-twenty risk exposure, the ATWACC represents one reasonable, conservative estimate of those potential costs. The cost of risk and other assumptions would be periodically reviewed to maintain alignment with potentially changing market fundamentals.

104. As an illustration of this calculation, consider a Capacity Market Seller with a resource that PJM assesses would face a $150/MW-day penalty risk as the 95th percentile of the unit-specific penalty/bonus distribution assessed as described above. If the ATWACC representing the cost of risk is equal to 10%, PJM's assessment of the resource-specific CPQR would be $15/MW-day.

105. Note that this approach, in combination with the stop-loss, provides an upper limit on the standard estimate of CPQR across all resources. In particular, the proposed stop-loss caps any participants' exposure at 1.5 times the Base Residual Auction clearing price; by definition this "extreme value" must be at or above the 95th percentile of the distribution of potential net penalties described above. Thus, the standard CPQR assessment can be no higher than the expected Base Residual Auction clearing price multiplied by the cost of risk. For a cost of risk of 10%, as in the example directly above, the CPQR can be no higher than ten percent of the expected auction clearing price. Thus, this approach conservatively limits the potential CPQR costs that Capacity Market Sellers can express in capacity sell offers without providing substantial evidence to support and justify the need to offer at higher levels.

VI.B FORWARD-LOOKING ESTIMATE OF NET ENERGY & ANCILLARY SERVICES REVENUE

106. Through this filing, PJM is also proposing to adopt a forward-looking approach to determine the net energy and ancillary service revenues ("Net EAS"), in the context of the Market Seller Offer Cap and the Minimum Offer Price Rule, that a resource can reasonably be expected to earn in PJM participating in the energy and ancillary service markets. To that end, PJM proposes to replace the existing tariff provisions as they relate to the Net EAS calculation in the Market Seller Offer Cap and the Minimum Offer Price Rule ("MOPR"), which currently calculate Net EAS revenues based on a historical rolling average. Instead, PJM proposes to utilize a

forward looking Net EAS methodology that will instead use forward-looking electricity and fuel data.[17] This approach effectively adopts the same one that the Commission previously approved.[18]

107. As part of this proposal, PJM will also employ the same Projected EAS Dispatch model for the determination of energy and ancillary services revenues for dispatchable resources that the Commission recently approved as part of PJM's 2022 Quadrennial Review.[19] In addition, all generation resource types will continue to be credited with revenues for providing reactive service.

108. A forward-looking approach necessarily relies on forward-looking data, and PJM's approach is grounded in forward energy and fuel prices at liquid trading points for the subject Delivery Year. Because buyers and sellers reflect anticipated changes in market design when transacting on a forward basis, the EAS Offset should reflect forward expectations. That is, as a liquid forward energy market should reflect market design changes in forward prices, the EAS Offset will also account for such market design changes.

109. The proposed approach forecasts EAS revenues using a Projected EAS Dispatch Model, as explained in detail below, to strengthen the connection between liquid forward market prices and expected resource revenues. This change affects only the EAS Offset determination for dispatchable resources, e.g., natural gas-fired combustion turbine ("CT"), natural gas-fired combined cycle ("CC"), coal-fired steam turbines, and storage resources; PJM will use an assumed output model, also utilizing forward energy and fuel prices, as applicable, for nuclear, wind, and solar, when developing the forward EAS Offset as described below.[20] The Projected EAS Dispatch model is more consistent with commercial expectations of the revenue a resource can reasonably expect to earn in PJM's energy and ancillary services markets. As a result, the offers in the capacity market will better reflect the costs that a resource actually needs to recover through the capacity market.

110. PJM accordingly proposes a common forward-looking EAS Offset estimating method, with three main components, that is adaptable to each of these existing Tariff applications of the EAS Offset:

---

[17] Given that PJM is proposing to implement the forward-looking EAS Offset commencing with the Base Residual Auction for the 2025/2026 Delivery Year so as to appropriately harmonize, the Tariff revisions included in this filing make clear that the existing historical EAS Offset approach will remain in place for the Incremental Auctions for the 2024/2025 Delivery Year and the forward-looking EAS Offset will apply for the 2025/2026 Delivery Year and subsequent Delivery Years. The revisions updating the determination of the Market Seller Offer Cap to a forward-looking approach also make clear that the new approach will apply for the 2025/2026 Delivery Year and subsequent Delivery Years. *See* proposed Tariff, Attachment DD, section 6.8(d-1).

[18] *PJM Interconnection, L.L.C.*, 173 FERC ¶ 61,134 (2020), *order on reh'g*, 174 FERC ¶ 61,180 (2021).

[19] *See PJM Interconnection, L.L.C.*, 182 FERC ¶ 61,073 (2023).

[20] PJM typically does not dispatch such resource types and they generally do not ramp up or down their energy production in response to energy prices.

- Using publicly available energy and fuel price data from liquid forward markets for the same timeframe as the Delivery Year at issue, applying locational adjustments and hourly (for energy) and daily (for fuel) price shaping using commercially reasonable and customary methods;
- Running resource revenue models with the forward-based energy and fuel prices, and key resource characteristics and parameters, as inputs, using two basic model types:
    - A Projected EAS Dispatch Model for dispatchable resources; or
    - An assumed output model, for non-dispatchable resources, applied to the forward energy prices referenced above; and
- Estimating market-based ancillary service revenues using ancillary services prices in co-optimized dispatch models, plus cost-based reactive service revenues.

111. PJM proposes to adapt and apply that general method to estimate:

- The EAS Offsets for resource-type default MOPR Offer Floor Prices, using resource-type-appropriate fuel and assumed output or Projected EAS Dispatch models;
- EAS Offset determination methodologies for resource-specific exceptions to the MOPR Floor Offer Prices, with certain defined flexibility, and certain defined limitations; and
- EAS Offset determination methodologies for resource-specific Market Seller Offer Price Caps.

1. Description and justification of main components of the overall forward EAS Offset estimating method.

<u>a. PJM's proposed changes base EAS Offset estimates for a Delivery Year on the energy and fuel prices in liquid futures markets for the time frame of that Delivery Year.</u>

112. The Brattle/S&L experts "recommend that PJM adopt the principles and methods we would use when supporting a client in an investment or contract decision for a similar timeframe," including "rely[ing] on market prices to the extent they are observable."[21] The Brattle/S&L experts accordingly "recommend using forward prices for electric energy and natural gas applicable to PJM market participants"

[21] Compliance Filing of PJM Interconnection, L.L.C., Docket No. EL19-58-003, Attachment C (Affidavit of Samuel A. Newell, James A. Read, Jr., and Sang H. Gang on behalf of PJM Interconnection, L.L.C.) ¶ 11 (Sept. 30, 2022) ("Brattle Aff."). As noted in the Brattle Aff., Dr. Samuel A. Newell "has frequently used forward markets as part of asset valuation assignments to support investment decisions by market participants," *id.* ¶ 2, while Mr. James A. Read Jr. "has worked with many companies on valuation and risk management assignments, including the development of forward price curves and the modeling and estimation of price volatility." *Id.* ¶ 3.

which "reflect expectations of market conditions at corresponding delivery dates and thus should incorporate assessments of the many factors that determine prices at delivery, including such factors as market design changes and additions and retirements of generation and transmission capacity."[22]

113. Several important design parameters flow from these principles. First, the forward prices used in the energy and ancillary services revenue estimates are best taken from liquid futures markets. When markets are liquid (i.e., there are substantial numbers of both buyers and sellers), settlement prices will better reflect Market Participants' expectations about future conditions. Such markets also post their settlement prices publicly, and mark to market daily, allowing current and prospective Market Participants to see the market's current collective judgment on expected future conditions and to react to those prices based on their own expectations of future conditions, and their knowledge of their own plans, transactions, and operations. Consistent with this important condition, the Brattle/S&L experts carefully assess market liquidity, and propose reliance on particular market hubs and products that trade with sufficient liquidity.

114. Second, futures market products, locations, and time periods do not automatically supply every assumption needed for every EAS Offset estimate required by the Tariff. Other forward markets can help fill some of those gaps, such as PJM's long-term Financial Transmission Rights ("FTR") auctions, which usefully reveal market expectations about future locational (congestion-based) price differences. For other aspects of the analysis, patterns established in historic data are reasonably used to adapt the output of futures markets to meet the need for particular inputs to the EAS Offset estimate.

115. Third, because "[t]he price of natural gas . . . is one of the principal drivers of electric energy prices," and "forward electricity prices on any given date will reflect forward natural gas prices on that same date," the forward EAS estimating methodology should be "sensitive to the alignment of forward price observation dates and forward contract delivery dates for power, natural gas, and other fuel commodities," and thereby "avoid systematic errors in forecasts of [EAS] margins."[23]

116. As explained in the following subsections, PJM's proposed use of energy and fuel prices in the EAS Offset estimating methodology takes account of these principles.

i. Forward electric energy prices

117. The proposed forward EAS Offset methodology will rely on futures markets prices. As explained by the Brattle/S&L experts, the established futures markets are well-suited to this purpose because:

- they are "marked to market and resettled on a daily basis;"

---

[22] Brattle Aff. ¶ 11.

[23] Brattle Aff. ¶ 49.

- they "determine a settlement price for each contract on each business day;" and
- "the sponsoring exchange makes its futures settlement prices public."[24]

118. The futures markets also trade multiple electric energy and natural gas products for delivery at multiple times and multiple locations in the PJM Region, and thus provide abundant, current, public data on forward prices needed for a forward EAS estimate.

119. However, not all of those products, locations, and delivery periods exhibit the liquidity desired for a reliable forward EAS estimate. The Brattle/S&L experts therefore assessed liquidity for multiple alternatives, and identified those with sufficient liquidity to use as a source of forward prices. In financial markets "liquidity" refers to how efficiently and easily trades can occur. Liquidity can and will change over time. For example, although the PJM Western Hub remains one of the most liquid trading hubs in the nation, activity at other trading hubs is evolving. Therefore, rather than locking in a fixed set of trading hubs or requiring the Commission to adjudicate in future proceedings the liquidity of individual trading hubs on a hub by hub basis, PJM is not proposing to embed in the Tariff, at least at this time, the specific products and hubs that the consultants identified in this analysis. Rather, PJM proposes to reflect in the Tariff that the particular hubs used for the EAS Offset will be specified in the PJM Manuals.

120. The Brattle/S&L experts use "open interest" as a gauge of futures market liquidity. Open interest in a futures market trading contract (i.e., a particular product for delivery at a particular place and time) "reflects the cumulative number of contracts that have been opened but not yet closed out or offset."[25] The Brattle/S&L experts explain that "the greater the open interest, the greater the amount of trading in the contract and thus the better the information revelation of market prices, other things being equal."[26] Moreover, "greater open interest and contract trade volumes reduce the chances that market prices can be manipulated successfully."[27]

121. For their liquidity analysis, the Brattle/S&L experts considered the open interest "at each of the trading hubs and transmission zones in PJM that are reported by [Intercontinental Exchange, Inc. ("ICE")]."[28] To measure open interest, they considered all products in the same product family (i.e., day-ahead peak, day-ahead off peak, real-time peak, and real-time off peak) because "the settlement

---

[24] Brattle Aff. ¶ 46.

[25] Brattle Aff. ¶ 47. To be clear, there is a futures contract with a buyer and seller; the interest is "open" only because it has not yet gone to delivery or been liquidated.

[26] Brattle Aff. ¶ 48.

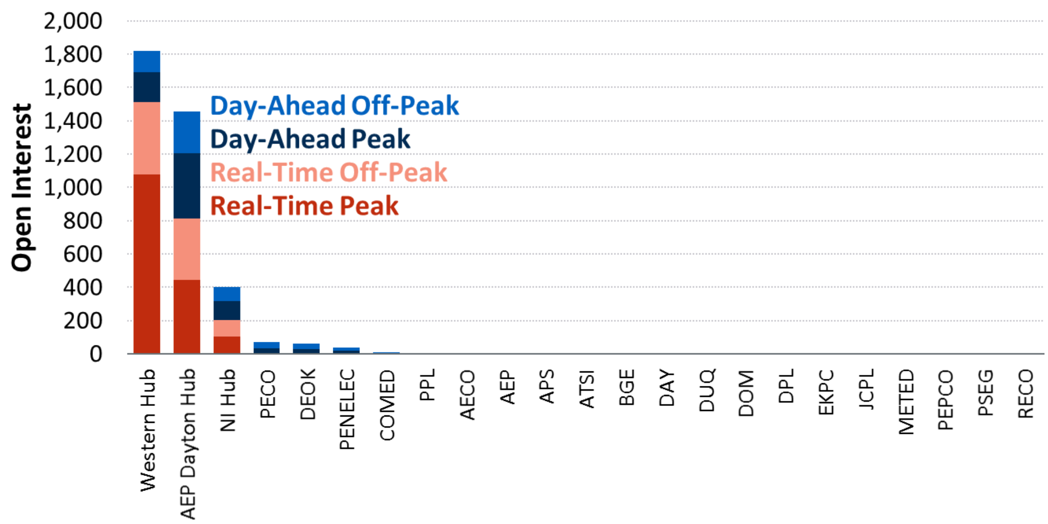
[27] Brattle Aff. ¶ 48.

[28] Brattle Aff. ¶ 50. They also checked open interest on electricity contracts traded on New York Mercantile Exchange platforms, but found it was more limited than open interest on the ICE. *Id.*

prices for day-ahead and real-time contracts for long-term futures . . . are nearly identical," and "the aggregate level of activity [for the related products reasonably] inform[s] the level of liquidity."[29] For both the forward price and liquidity analyses Brattle conducted in 2020, Brattle reviewed prices for 2024, reflecting that PJM typically will undertake its pre-auction energy and ancillary services revenue estimating analyses roughly four years before the relevant Delivery Year.[30]

122. The results of their liquidity analysis are shown in Figure 1 below, which is reproduced from the Brattle Affidavit.

Figure 1: Open Interest for PJM Futures Products at Trading Hubs and Zones for Calendar Year 2024



123. As can be seen, open interest for these PJM energy products in 2024 was substantial for the three traded PJM Region hubs, but minimal to non-existent for the 20 traded PJM Region zones. Looking beyond 2024 to additional years, the Brattle/S&L experts also note that open interest at the PJM Zones "is . . . inconsistent from year to year."[31] Based on these facts, in their affidavit, they recommended using electric energy futures settlement prices at PJM Western Hub, AEP-Dayton Hub, and Northern Illinois Hub ("NI Hub") for the forward EAS estimates.[32]

---

[29] Brattle Aff. ¶ 50.

[30] Brattle Aff. ¶ 51.

[31] Brattle Aff. ¶ 51.

[32] Brattle Aff. ¶ 14.

124. PJM's proposed approach, per the Brattle/S&L experts' recommendation,[33] averages the settlement prices reported for the 30 most recent trading days. This approach "balances the benefit of the most recent market information with potential vulnerability to market manipulation from indexing to a single day."[34]

125. PJM also proposes to use the day-ahead product's future prices. As the Brattle/S&L experts explain, the day-ahead and real-time futures prices "are nearly equivalent, such that relying on either will have little to no impact on the estimated E&AS net revenues."[35] PJM adopts their recommendation to use the day-ahead product prices. Moreover, the monthly prices from the day-ahead futures can be used to develop both hourly day-ahead prices and hourly real-time prices, relying on the distinct patterns of day-ahead and real-time hourly price shapes in the recent historic record, as discussed below.

126. In sum, the end result of this step of the analysis is forward day-ahead energy prices for each of the three PJM hubs, and for each month, on-peak period, and off-peak period in the Delivery Year.

ii. Determination of zonal prices

127. As noted above, there is little trading of day-ahead or real-time energy futures for delivery to individual PJM Zones in 2024, and the little trading observed is inconsistent from year-to-year. The Brattle/S&L experts correctly observe that "[t]he limited liquidity of zonal futures makes them more vulnerable to manipulation, which could cause large distortions in the capacity market parameters and outcomes."[36] While the zonal futures prices themselves should therefore be avoided in the analysis, fairly high correlations in historic prices between each hub and specific Zones enable ready mapping of Zones to hubs.

128. Specifically, the Brattle/S&L experts "analyzed the correlation of historical prices between the three electricity hubs and the 20 PJM zones, using monthly average peak and off-peak data," and found that "for each zone, the hub with highest price correlation is that which is geographically closest," and this correlation persisted for both peak and off-peak prices.[37] The resulting hub-Zone mapping is shown in the Brattle Affidavit.[38]

---

[33] Brattle Aff. ¶ 16. Note that the daily interval here refers to settlement price updating. The underlying product is monthly (e.g., delivering energy at the specified location every day for the month of July 2024).

[34] Brattle Aff. ¶ 16. To implement the recommended 30-day averaging, PJM plans to retrieve, 180 days before the start of each Base Residual Auction, forward pricing data for each month of the future Delivery Year, and will use the daily settlement data from the 30 trading days prior to that date. This will provide PJM with time to calculate the EAS Offsets for the reference resources prior to having to post the preliminary default MOPR Floor Offer Prices at 150 days prior to the auction.

[35] Brattle Aff. ¶ 16; *see* Tariff, Attachment DD, section 5.10(a)(v-1)(C)(2).

[36] Brattle Aff. ¶ 51.

[37] Brattle Aff. ¶ 53.

[38] Brattle Aff. ¶ 53.

129. This mapping does not mean that PJM proposes simply to adopt for each Zone the price in the hub to which it is mapped. Rather, this mapping defines the appropriate sources and sinks for determining locational basis differentials between each Zone and its mapped hub. Adding these differentials to the mapped hub price determines the corresponding Zone price.

130. PJM proposes to use forward market information (i.e., long-term FTR auction results), along with historic data on marginal losses, to calculate forward monthly peak and off-peak prices for each Zone. This is not a novel approach. As the Brattle/S&L experts explain, their "standard practice" for estimating future congestion differentials a few years out "is to use differences in congestion prices between each zone and the hub, from the latest long-term [FTR] auction."[39]

131. The longest-term FTRs traded in PJM's auctions are three years forward.[40] Even allowing for the fact that the latest long-term FTR auction results available at the time of PJM's EAS Offset calculations will be for the Delivery Year prior to that for which the Base Residual Auction is being run, "[t]he long-term FTRs are a reasonable indicator of the market's view of future congestion applicable in the [D]elivery [Y]ear and will reflect shifting patterns much more quickly than, for example, relying on historical congestion differentials from four to six years before the [D]elivery [Y]ear."[41]

132. As the Brattle/S&L experts explain, PJM's "long-term FTR auctions are centralized, multilateral, and locational-based markets, producing nodal clearing prices . . . . determined by bids from many market participants for source-sink pairs across the PJM system;" and have been found competitive, with ownership unconcentrated.[42] The consultants also "analyzed how well historical long-term FTR prices align with realized congestion in the day-ahead market between the trading hubs and zones during the same delivery years."[43] Although "[l]ong-term FTRs of course do not accurately predict the realized congestion in the delivery year due to the uncertainty of the market conditions . . . FTR prices do incorporate trends . . . [and therefore] [u]sing FTR prices to forecast basis differentials incorporates such shifts sooner than using trailing historical prices to forecast [basis differentials]."[44]

---

[39] Brattle Aff. ¶ 17.

[40] *See* Tariff, Attachment K – Appendix, section 7.1A.1; Amended and Restated Operating Agreement of PJM Interconnection, L.L.C., Schedule 1, section 7.1A.1.

[41] Brattle Aff. ¶ 17. Although the Market Monitor has claimed that FTRs systematically understate congestion, their analysis ultimately shows only that it is hard to predict congestion occurring several years hence. By contrast, the Brattle/S&L experts explain that the specific Hub-to-zone FTRs relevant here do not appear systematically mis-priced based on the available evidence. *Id.* ¶¶ 54-56.

[42] Brattle Aff. ¶ 54.

[43] Brattle Aff. ¶ 55.

[44] Brattle Aff. ¶ 55 (citing example of regional price shifts from Marcellus shale gas production).

133. In addition to the congestion differences, Zonal prices also need to incorporate the marginal losses expected between the hub and its mapped Zones. This adjustment is reasonably performed using historical zonal day-ahead loss prices (scaled by the relationship between the forward price at the hub and the historic day-ahead Locational Marginal Pricing ("LMP") for the hub. Such use of historic loss data "[is] sufficient because losses tend to be relatively small and more stable over time, and there is no forward-looking, market-based source for directly estimating future losses."[45]

134. The end result of this step of the analysis is forward day-ahead energy prices for each of the 20 PJM Zones, and for each month, on-peak period, and off-peak period in the Delivery Year.

iii. Forward natural gas prices

135. Fuel costs are a critical input to the energy and ancillary services revenue estimates as they are the principal cost incurred by most resources to obtain energy revenues. For the forward EAS Offset methodology, PJM proposes to use fuel futures market prices in a manner similar to the proposed methodology's use of electric energy futures market prices. This discussion focuses on natural gas prices, since the Reference Resource assumed for setting the VRR Curve is natural gas- fired. The approach for other fuels is adjusted as necessary, as discussed later.

136. As with energy futures prices, there are multiple futures markets for natural gas deliveries to PJM Region locations, but the liquidity of those markets varied for the 2024 time period used to match the energy futures prices. As with electric energy futures, open interest is also reported for these natural gas futures trading hubs, which enables a reasonable assessment of liquidity. As explained in their affidavit, the Brattle/S&L experts found six gas hubs with sufficient liquidity (i.e., Chicago, Transco Zone 6 (non-NY), Dominion South, Michcon, TETCO M3, and Columbia-Appalachia TCO),[46] based on the open interest results summarized in their Figure 4.[47]

137. The PJM Region is also served by three other natural gas hubs, (i.e., Transco Zone 6 (NY), TGP LA 500 Leg, Transco Zone 5 Delivered) but their 2024 futures markets were not sufficiently liquid to rely on their settlement prices. However, based on historical price correlations, each of these hubs can be mapped to one of

---

[45] Brattle Aff. ¶ 18. Specifically, PJM will calculate the added loss differential as the average of the difference between the loss components of the historical on peak or off peak day-ahead LMPs for the Zone and relevant hub in that month across the three year period scaled by the ratio of the forward monthly average on-peak or off-peak day-ahead LMP at such hub to the average of the historical on-peak or off-peak day-ahead LMPs for such hub in that month across the three year period.

[46] Brattle Aff. ¶¶ 29, 66.

[47] Brattle Aff. ¶ 66.

the six hubs that is sufficiently liquid in the 2024 futures market.[48] Once mapped, forward prices for these less-liquid hubs can be derived "by scaling the forward price of the mapped hub by the average ratio of monthly prices at the illiquid hub and the mapped [liquid] hub over the most recent three years."[49] This reliance on historic data is reasonable. The three hubs are only illiquid *in the futures market*; the locations were actively traded in the historic period, permitting reasonable assessment of the relationship between prices at these hubs and prices at the hub to which they are mapped.

138. PJM proposes to use a simple average of natural gas settlement prices for the most recent 30 trading days, for the same reasons noted above for the forward energy prices.[50] Finally, PJM will assign prices from the nine natural gas futures trading hubs to the 20 PJM Zones using the hub-zone mapping previously developed and recorded in PJM Manual 18.

iv. Shaping futures market monthly prices to the hourly and daily prices needed to make resource revenue estimates

139. The steps above produce monthly forward prices for electric energy and natural gas. Estimating resource revenues, however, requires prices on a shorter timescale, to capture the changing operating and economic conditions that drive resource dispatch, output, and revenues. Energy prices by hour, and natural gas prices by day, provide reasonable granularity for purposes of the estimate given this matches the timescale of the day-ahead energy and gas markets. Historic data can help fill this gap.

140. For this purpose, one could shape monthly prices to hourly prices based on historic multi-year relationships, and then run the dispatch model using those prices. Different years will exhibit different pricing patterns; simply averaging price variations across multiple years will mute the in-year volatility that significantly affects resource revenues. That approach also would not sufficiently respect the strong relationship between electric energy prices and fuel prices. Trying to match, for example, a multi-year average pattern of gas prices to a multi-year average pattern of energy prices could ignore that a strong natural gas price trend produced a strong energy price trend. A synthetic year that tries to encompass multi-year pricing pattern variations thus may be *too* synthetic, and therefore less realistic. As the Brattle/S&L experts explain, "[h]istorical price patterns provide the best information for the hourly shapes of day-ahead and real-time prices,"

[48] Brattle Aff. ¶ 66 & Table 6. PJM has memorialized this mapping in Manual 18. *See* Capacity Market & Demand Response Operations, *PJM Manual 18: PJM Capacity Market*, PJM Interconnection, L.L.C. (July 26, 2023), http://www.pjm.com/-/media/documents/manuals/m18.ashx.

[49] Brattle Aff. ¶ 30. Note that this use of historic prices to estimate monthly natural gas prices at illiquid hubs differs from the three simulations, discussed below, that each use one of three recent years of hourly price shaping data.

[50] Brattle Aff. ¶ 16. Specifically, PJM will retrieve the forward gas price data 180 days before the relevant Base Residual Auction, and use data from the 30 preceding trading days at that time.

which warrants "using the price patterns from each of the three most recent years to capture random variation in price shapes from year to year."[51]

141. For this reason, PJM's proposed approach is more sophisticated, using historic pricing patterns from each of the three most recent years to produce three years of shaped hourly energy forward prices and shaped daily natural gas forward prices, and *then* running the revenue model separately for *each* of those years. Under this approach, the revenues resulting from those three years are averaged to produce an annual EAS estimate that reasonably encompasses varying patterns in hourly energy or daily natural gas prices. PJM will produce hourly energy prices for each Zone, for each applicable generation bus,[52] and for the PJM Region.[53]

142. Specifically, PJM proposes to:

- Separately consider hourly electric energy prices and daily gas prices from each of the three most recent years, for three separate analyses;
- For each monthly on-peak period and off-peak period within a given historic year, develop an hourly energy price shape by dividing each individual hour's Day-ahead or Real-time LMP by the average Day-ahead or Real-time LMP across all hours in the given period;
- Apply that shape to the corresponding monthly on-peak period or off-peak period day-ahead price developed from the energy futures markets in the steps described above, to produce hourly energy prices for each hour in those periods, and thus for each hour of the year;
- Develop daily natural gas price shapes in the same way, deriving in-period daily price patterns for each month of the historic year, and applying those patterns to the corresponding monthly prices developed from the natural gas futures markets;
- Use the shaped forward hourly energy prices and shaped forward daily natural gas prices developed using shapes from each historic year;
- Calculate net EAS revenues for each of those years using the appropriate model for the resource under consideration; and
- Average the resulting three years of revenues to produce a single-year estimate.

---

[51] Brattle Aff. ¶ 19.

[52] PJM will also determine prices to each applicable generation bus for use in determining resource-specific EAS Offsets by applying basis differentials from the Zone to the generation bus to the forward day-ahead and real-time hourly LMPs for the Zone.

[53] To determine the PJM Region forward energy prices, PJM will take the load-weighted average of the monthly on-peak and off-peak Zonal LMPs, developed using the historical average load for each on-peak and off-peak period. Then, PJM will shape those monthly values to forward hourly LMPs using the same shaping process for zonal forward hourly LMPs, but use historical LMPs "for the PJM Region pricing point," i.e., (Pricing Node ID 1: PJM-RTO). *Id.*

b. PJM is adding market-derived ancillary services revenues to the EAS Offset.

143. In addition to considering forward price data for energy and fuel, PJM is proposing to account for revenues from market-based ancillary service products in the EAS Offset, except for Regulation. The current EAS Offset approach omits such ancillary services, and instead only considers the cost-based revenues from providing reactive service as the representative of the estimated ancillary services revenues. Accordingly, PJM is proposing to continue to provide credit for reactive services *and* start to account for revenues from other market-based ancillary services in the EAS Offset.

144. To do so, PJM will use a new dispatch model (i.e., the Projected EAS Dispatch discussed in the next section) that co-optimizes energy and reserves, similar to PJM's Day-ahead and Real-time Energy Markets. However, as Brattle explains, there are no observable forward markets for such ancillary services, so PJM must rely on historical market prices for ancillary services.[54] Thus, for Synchronized and Non-synchronized Reserves, PJM will employ historical prices for these reserves in the Projected EAS Dispatch, where they will interact with the Forward Hourly LMPs, and commitment and dispatch projections for the resource will be made accordingly. PJM will use the historic real-time Synchronized and Non-Synchronized Reserve prices for simulated real-time reserve dispatch as a proxy for the unavailable historical day-ahead prices in the simulated day-ahead reserve dispatch. In other words, under PJM's new dispatch approach, it will determine revenues associated with Synchronized and Non-Synchronized Reserve on both day-ahead and real-time bases.

145. For Secondary Reserve, at this time, PJM is proposing to set the clearing price for Secondary Reserves to $0.00/MWh for both the day-ahead and real-time dispatch simulations. This is grounded in the fact that PJM's simulations have shown very low prices for Secondary Reserve ($0.00/MWh once rounded to the nearest penny),[55] and Brattle's conclusion that even without setting the price at $0.00/MWh, the product would not materially affect resources' net EAS revenues.[56] Accordingly, PJM's approach for Secondary Reserves is reasonable.

146. As PJM, Brattle and S&L worked on putting together a process to estimate forward ancillary services prices, the primary method discussed was one similar to that used for Regulation (explained further below)—to scale historic reserve market clearing prices by the ratio of the forward energy prices to the historic energy prices. While in the long-term, such an approach may be suitable, this could result

[54] Brattle Aff. ¶ 22.

[55] *See* Enhanced Price Formation in Reserve Markets of PJM Interconnection, L.L.C., Docket No. EL19-58-000, at 105 (Sept. 29, 2019) (citing *id.*, Attachment D (Affidavit of Adam Keech on Behalf of PJM Interconnection, L.L.C.) ¶ 42, Table 4).

[56] Brattle Aff. ¶ 62.

in scaling *down* reserve market clearing prices in some cases.[57] As a result, and in an effort to not introduce arbitrary bias into the new approach, PJM proposed to use unscaled, historic ancillary services market clearing prices for the initial implementation.

147. This approach for determining market-based ancillary services revenues is necessarily limited to only dispatchable resources. Thus, only CT, CC, coal, and storage resource types will, by default, be credited with revenues for Synchronized Reserve, Non-synchronized Reserve, and Regulation, as these resource types are inherently capable of reliably ramping up or down their energy production when called upon to deploy. All resource types will continue to get credit for providing reactive services.

148. Consistent with PJM's existing Tariff, sellers of resources that rely heavily on ancillary services for annual revenues may seek to use an alternate approach through a resource-specific determination. Indeed, any Capacity Market Sellers that would like a different ancillary revenues estimate for its resource's EAS Offset than one determined using the process outlined above and detailed in the Brattle Affidavit can seek a resource-specific exception and establish the resource's Market Seller Offer Cap through that process.[58] For example, and subject to the strictures of the resource-specific exception process,[59] if a seller of a wind, solar, nuclear, or demand response resource would like to reflect revenues from the dispatched ancillary services in the EAS Offset for its resource, then the seller will need to demonstrate that its resource can earn (or has earned) revenues providing these reserve products.

149. In addition, as discussed below, under the resource-specific exception process, sellers may propose to use different forward prices for ancillary services, but such prices must be from a publicly available source or be otherwise readily available (like through a subscription service) and demonstrated to be more appropriate for use on a resource-specific basis than the methodology set forth herein and in the Tariff.

c. <u>Replacing the Peak-Hour Dispatch model with the Projected EAS Dispatch model that simulates dispatch for all hours in a day with the objective of optimizing the resource's dispatch in response to input prices.</u>

150. Once the forward energy and fuel prices, and the ancillary services prices, have been developed, PJM will input those, along with the applicable resource's operating parameters, into a dispatch model to determine an estimate of the resource's expected energy and ancillary services revenues for the future Delivery Year. Brattle/S&L observes that "this is best done with an optimization model that, like PJM's actual market, puts each resource to its highest value use,

[57] *See* Brattle Aff. at Table 2.

[58] *See* proposed Tariff, Attachment DD, sections 5.14(h-2)(3)(A) & (B)(ii).

[59] *See* proposed Tariff, Attachment DD, sections 5.14(h-2)(3).

recognizing each resource's capabilities, costs, and operating constraints."[60] However, PJM's new dispatch model will only apply to dispatchable resources, e.g., CT, CC, coal, and storage, while PJM will continue to use an assumed output model for nuclear, wind, and solar, as PJM typically does not dispatch such resource types and they generally do not ramp up or down their energy production in response to energy prices.

151. Accordingly, as part of the updated EAS Offset approach, PJM is proposing to switch from using the Peak-Hour Dispatch market simulation to a "Projected EAS Dispatch" simulation. The Projected EAS Dispatch approach, like the existing Peak-Hour Dispatch, takes the input prices as given and treats each generator as a price-taker, assuming that the reference resource will run when the estimated forward LMP exceeds the cost of operating the resource, without consideration of supply/demand balancing. However, the Projected EAS Dispatch approach will simulate whether the reference resource will run in any hour of the day and for any "contiguous period(s)," in which the resource would generate at a profit, whereas the Peak-Hour Dispatch only simulates whether the reference resource may be dispatched into the day-ahead and real-time energy market in four independent, four-hour blocks (between hour ending 8:00 and hour ending 23:00) each day. Further, the Peak-Hour Dispatch model does not account for ancillary service commitment and dispatch, unlike the Projected EAS Dispatch approach, which co-optimizes a resource's commitment and dispatch between the energy and ancillary service markets. Thus, Projected EAS Dispatch better simulates actual market outcomes and is more consistent with the resource's commercial expectations. As Brattle explains, PJM will employ "an industry-standard simulation model" that allows for "the same approach we often use in commercial applications."[61] To effectuate this change, PJM is utilizing the defined "Projected EAS Dispatch" for calculating future EAS Offsets.

152. To implement the Projected EAS Dispatch, PJM will employ a simulation software that offers a broad range of capabilities for modeling and optimization of energy systems.[62] Because the purpose of the exercise is to determine a resource's expected revenues, PJM will set the software's objective function to optimize the energy and ancillary services commitment and dispatch of the generator in order to maximize the resource's value (as measured by net profit) based on the input energy and ancillary service and fuel prices discussed above, subject to the constraints of the generator parameters.[63] To do so, the model will compare an energy offer, composed of the resource's marginal costs and other costs associated with generating energy, and including the cost for a complete start and shutdown cycle.

[60] Brattle Aff. ¶ 37.

[61] *See* Brattle Aff. ¶

[62] Brattle Aff. ¶ 37.

[63] *See* Tariff, Definitions O-P-Q (defining Projected EAS Dispatch).

153. The Projected EAS Dispatch will simulate commitment and dispatch for both the day-ahead and real-time energy and ancillary service markets. Similar to the sequencing of the day-ahead and real-time markets, the model will first run a day-ahead commitment and dispatch against the input forward day-ahead energy and ancillary service prices. A real-time commitment and dispatch against forward real-time energy and ancillary service prices is then run where the model assumes the resource runs in real-time for the periods in which it was committed day-ahead, but adjusts the dispatch for such hours based on the forward real-time LMPs and ancillary service prices. The resource may also be committed and dispatched for additional hours beyond those for which it was committed day-ahead. The gross revenues from such dispatch are then calculated assuming all day-ahead committed MWh are paid the forward day-ahead energy or ancillary service market clearing prices, as appropriate, and that any deviations between the real-time dispatch and the day-ahead dispatch are settled at the forward real-time energy or ancillary service market clearing prices, as appropriate. The settlement includes make-whole payments such that total gross revenues cover resource's real-time costs.

154. Thus, the Projected EAS Dispatch will forecast revenues from the resource based on the optimal commitment and dispatch of the resource per the objectives of the PJM energy and ancillary service markets, thus approximating actual resource behavior and reasonable commercial expectations.[64] To determine the "net" revenues that will comprise the EAS Offset, PJM subtracts the costs to generatethe energy MWh for the hourly intervals in which the resource is dispatched in the real-time model (i.e., incremental energy costs, plus startup and shutdown costs).

155. To further approximate actual resource operations and commercial expectations, PJM will adjust the net revenues yielded by the model to linearly scale down the revenues to account for the resource's expected and unplanned outages. PJM will also assume maintenance outages. For example, PJM will assume CT and CC resources take a two-week maintenance outage during the shoulder month of October, when such resources often take scheduled outages.

156. The resulting simulated generation pattern and the corresponding revenues net of operating costs for each day of the Delivery Year yield the projected energy revenue portion of the EAS Offset for each reference resource. PJM performs this simulation with energy, ancillary services, and fuel prices shaped by historical data from each of the three full preceding calendar years, and then takes the average of the revenues yielded by the three simulations as the EAS Offset value for the resource.

[64] To the extent the simulation produces the scenario in which the unit cannot recover its real-time generation cost for the day (e.g., real-time LMPs that are lower than the day-ahead LMPs on which the resource was committed), the model credits the resource with an "uplift" (or make-whole) payment equivalent to the difference between the real-time generation cost and the revenue from energy an ancillary services. As such uplift payments occur in the same manner in PJM's energy markets today, the Projected EAS Dispatch model is simply and reasonably approximating PJM's energy markets.

157. The methodology for calculating the net energy revenue offset is the same methodology approved previously by the Commission.[65] While the methodology is the same, the underlying values have had updates. This is expected as there is more recent and relevant data available now compared to when the original filing was made.

158. The net energy revenue offset is estimated for each resource class type in each Zone using the average of the annual net energy revenues from 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 described below. Ancillary service revenues are assumed to be the average of the previous three years of posted data from the Market Monitor's Annual State of the Market Report[66] for each resource type except for the combined cycle for which the ancillary service revenue is assumed to be the currently prescribed value for the Reference Resource combined cycle in section 5.10(a)(v)(A) of the Tariff, Attachment DD. Section 5.14(h-2) of the Tariff, Attachment DD provides the following methodologies for calculating EAS values for new resources subject to MOPR:

- For nuclear resource type, the net energy and ancillary services revenue estimate for each Zone shall be determined by the gross energy market revenue determined by the product of [average annual day-ahead Forward Hourly LMPs for such Zone, 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 for the 2025/2026 Delivery Year[67], or starting with the 2026/2027 Delivery Year and subsequent Delivery Years, $7.99/MWh for a single unit plant or $7.74/MWh for a multi-unit plant[68]] where these hourly cost rates include fuel costs and variable operation and maintenance expenses, inclusive of Maintenance Adder costs, plus reactive services revenue of $2,251/MW-year[69];

---

[65] *See PJM Interconnection, L.L.C.*, 182 FERC ¶ 61,073 (2023); *PJM Interconnection, L.L.C.*, 173 FERC ¶ 61,134 (2020).

[66] *State of the Market Report for PJM – Volume 2: Detailed Analysis*, Monitoring Analytics, LLC, Table 7-3 (Mar. 9, 2023), https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2022/2022-som-pjm-vol2.pdf.

[67] *Gross Avoidable Cost Rates for Existing Generation and Net Cost of New Entry for New Energy Efficiency*, The Brattle Group and Sargent & Lundy, 7-10 (Mar. 17, 2020), https://www.brattle.com/wp-content/uploads/2021/05/19714_gross_avoidable_cost_rates_for_existing_generation_and_net_cost_of_new_entry_for_new_energy_efficiency.pdf ("2020 Brattle Report").

[68] *Gross Avoidable Cost Rates Existing Generation*, The Brattle Group and Sargent & Lundy, 16-19 (Jan. 9, 2023), https://www.pjm.com/-/media/committees-groups/committees/mrc/2023/20230223/20230223-item-02---4-brattle-gross-avoidable-costs-for-existing-generation-report.ashx ("2023 Brattle Report").

[69] *Id*.

- For coal resource type, the net energy and ancillary services revenue estimate for each Zone shall be determined by the Projected EAS Dispatch of a 650 MW coal unit (with heat rate of 8,638 BTU/kWh[70] and variable operations and maintenance variable operation and maintenance expenses, inclusive of Maintenance Adder costs, of $9.50/MWh[71] for the 2025/2026 Delivery Year, or starting with the 2026/2027 Delivery Year and subsequent Delivery Years, $10.92/MWh[72]) using day-ahead and real-time Forward Hourly LMPs for such Zone and Forward Hourly Ancillary Service Prices, and daily forecasted coal prices, as set forth in the PJM Manuals, plus reactive services revenue of $2,217/MW-year[73];

- For the 2025/2026 Delivery Year, for combustion turbine resource type, the net energy and ancillary services revenue estimate for each Zone shall be determined by the Projected EAS Dispatch of a single General Electric Frame 7HA turbine with evaporating cooling, Selective Catalytic Reduction technology, with dual Fuel capability, with the heat rate assumed for the combustion turbine resource shall be 9,134 BTU/kWh, the variable operations and maintenance expenses for such resources, inclusive of Maintenance Adder costs, shall be $6.93/MWh, plus ancillary services revenue of $2,199/MW-year.[74] Starting with the 2026/2027 Delivery Year and subsequent Delivery Years, for combustion turbine resource type, the net energy and ancillary services revenue estimate for each Zone shall be determined by the Projected EAS Dispatch of a single General Electric Frame 7HA.02 turbine with evaporating cooling, Selective Catalytic Reduction technology, with the heat rate assumed for the combustion turbine resource shall be 9,189 BTU/kWh[75], the variable operations and maintenance expenses for such resources, inclusive of Maintenance Adder costs, shall be $1.19/MWh[76], plus ancillary services revenue of $3,565/MW-year;[77]

---

[70] *See Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies*, U.S. Energy Information Administration, Table 2-1 (Feb. 2020), https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf ("EIA Study").

[71] *See* 2020 Brattle Report at 10-13.

[72] *See* 2023 Brattle Report at 19-24.

[73] *Id*.

[74] These values align with the Reference Resource combustion turbine specifications at described in Tariff, Attachment DD, section 5.10.

[75] *See PJM CONE 2026/2027 Report*, The Brattle Group, v (Apr. 21, 2022) https://www.pjm.com/-/media/library/reports-notices/special-reports/2022/20220422-brattle-final-cone-report.ashx ("2022 CONE Report").

[76] 2022 CONE Report at 63. The variable O&M costs for the CONE Areas are: $1.19/MWh (EMAAC); $1.18/MWh (SWMAAC); $1.15/MWh (Rest of RTO); and $1.22/MWh (WMAAC).

[77] *Id*.

- For combined cycle resource type, for the 2025/2026 Delivery Year, the net energy and ancillary services revenue estimate for each Zone 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 6,501 BTU/kwh, the variable operations and maintenance expenses for such resource, inclusive of Maintenance Adder costs, shall be $2.11/MWh, plus reactive services revenue of $3,350/MW-year. Starting with the 2026/2027 Delivery Year and subsequent Delivery Years, for combined cycle resource type, the net energy and ancillary services revenue estimate for each Zone shall be determined in a manner consistent with the methodology described in Tariff, Attachment DD, section 5.10(a)(v-1)(B) for the Reference Resource combined cycle;

- For solar PV resource type, the net energy and ancillary services revenue estimate for each Zone 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 Forward Hourly LMP for such Zone and applicable to such hour with this product summed across all of the hours of an annual period, plus reactive services revenue of $6,791/MW-year.[78] Two separate solar resource models are used, one model for a fixed panel resource and a second model for a tracking panel resource;

- For onshore wind resource type, the net energy and ancillary services revenue estimate for each Zone 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 Forward Hourly LMP for such Zone applicable to such hour with this product summed across all of the hours of an annual period, plus reactive services revenue of $4,027/MW-year;[79]

- For offshore wind resource type, the net energy and ancillary services revenue estimate for each Zone shall be determined by the gross energy market revenue equal to the product of [the average annual real-time Forward Hourly LMP for such Zone times 8,760 hours times an assumed annual capacity factor of 45%], plus reactive services revenue of $4,027/MW-year;[80] and

---

[78] *Id*.

[79] *Id*.

[80] *Id*.

- For Capacity Storage Resource, the net energy and ancillary services revenue estimate shall be estimated by the Projected EAS Dispatch of a 1 MW, 4MWh resource, with an 85% roundtrip efficiency, and assumed to be dispatched between 95% and 5% state of charge against day-ahead and real-time Forward Hourly LMPs for such Zone and Forward Hourly Ancillary Service Prices, plus reactive services revenue of $3,903/MW-year.[81]

VII. CONTINUED EVOLUTION OF THE PJM CAPACITY MARKET

159. The long-term integrity and sustainability of the PJM capacity market relies on its ability to represent the supply and demand dynamics it was structured to address. Over time, certain foundational assumptions may no longer hold due to cumulative changes in supply and demand fundamentals since the initial development of the market. No market – or administrative construct attempting to uphold competitive market principles – is final or unalterable. PJM has the responsibility to continually refine its markets to align with the evolving realities of the power system and maintain a coherent and relevant market structure. It is PJM's role and indeed imperative to continually evolve the wholesale markets, including the Reliability Pricing Model, in such a way to best reflect the most salient "ground truth" elements of the power system and translate into a workable and hopefully understandable market construct. This continuous adaptation is essential to sustain market relevance and integrity in a constantly changing environment.

160. Thus, there are a number of elements that PJM anticipates will continue to evolve in the pursuit of "more perfect" markets, including, at least: seasonal or other more granular capacity market design; evolution in understanding of distribution of potential delivery-year weather patterns and related enhancements to risk assessments; and accreditation enhancements to more accurately value the expected contribution to reliability of different resources.

161. PJM plans to continue to evaluate potential approaches to enhance and improve our understanding of the distribution of potential delivery-year weather outcomes in the presence of climate change. As the global community becomes more cognizant of the impacts of climate change, the importance of adapting our wholesale markets in response to these evolving conditions becomes paramount. PJM recognizes the potential value of integrating historical weather assessments with forward-looking climate change adjustments to produce a more accurate and robust understanding of potential delivery-year weather outcomes. Such assessments are no longer just about analyzing past trends but must also incorporate projections that consider the increasing volatility and unpredictability brought about by global warming.

162. The ongoing and projected shifts in weather patterns, characterized by more frequent extreme events and seasonally skewed temperature variations, compel a

---

[81] *Id*. The $3,903/MW-year is the average of all technologies reactive service revenue, since there is no Capacity Storage Resource value calculated.

re-evaluation of how the power system is anticipated to respond. This not only has implications for resource availability and demand but also affects the grid's resilience in the face of these changing conditions. By proactively integrating climate science into its risk assessments, PJM can ensure that its markets are prepared to address the challenges of the future and not just those of the past.

163. While there did not appear to be sufficient scientific consensus regarding a path forward in the short term, recognizing the potential for climate change to further alter traditional risk paradigms, PJM is committed to investing in research and collaboration with climate experts and with staff at other ISOs/RTOs and FERC to explore and develop alternative modeling techniques. The aim is to better anticipate, understand, and mitigate the effects of climate change on the reliability and efficiency of the power system.

164. Another crucial aspect of PJM's capacity market evolution will center on the refinement of accreditation modeling. The power system is increasingly characterized by uncertainty, underscoring the need for models that accurately capture the real-world complexities and limitations of resources. While the approach PJM has developed for this filing is a substantial step forward, a remaining challenge lies at the intersection of imperfect information about future system conditions and the inherent operational constraints of resources.

165. For instance, certain resources have prolonged start-up times or specific forward notification requirements. These operating parameters can impact how they respond to operator direction or market signals and, consequently, their contribution to system reliability. Models that do not factor in these operational limitations may over-estimate such resources' contribution to resource adequacy, and, in turn, relatively under-estimate the capacity contribution of more flexible resources. The difficulty of incorporating and implementing reasonable assumptions regarding operators' imperfect information about future conditions – be it changing weather patterns, sudden spikes in demand, or unexpected outages – further compounds the challenge.

166. PJM recognizes these complexities and is invested in the continued evolution of its accreditation modeling. The goal is to bridge the gap between theoretical modeling and real-world operational realities, ensuring that each resource's accreditation reflects its potential contributions and limitations. This will require a multi-faceted approach, integrating detailed operational data, stakeholder feedback, and advanced modeling techniques to continually evolve towards a more accurate, responsive and adaptive accreditation framework.

167. As this modeling continues to evolve, it will become instrumental in guiding investment decisions, operational strategies, and other market responses. By ensuring that the accreditation model accurately reflects the realities of power system operations, PJM aims to foster a market environment that is both efficient and resilient, ready to meet the demands of a dynamic and uncertain future.

168. This concludes my affidavit.

APPENDIX TO AFFIDAVIT:
NUMERICAL EXAMPLES OF BENEFITS OF MARGINAL ACCREDITATION

Encourages cost-effective investment and retirement of resources

Illustrative Example

- Suppose Resource X and Y have average and marginal ELCC values as shown in the table below.
  - 1 nameplate MW of Resource X adds the equivalent reliability value of 0.2 MW of perfect capacity.
  - 1 nameplate MW of Resource Y adds the equivalent reliability value of 0.8 MW of perfect capacity.
- Investment in Resource Y is 4x more effective in reducing load shed risk (per nameplate MW).
- Investment in Resource Y is 3x more costly (per nameplate MW).

Net Impact: Resource Y provides the more cost-effective solution with cost per added reliability value (reduction in load shed risk) being 75% that of Resource X – aligned with compensation and incentives under marginal approach.

Marginal clears the most cost-effective solution, while average clears the cheaper $/MW UCAP solution but pays more $ per reliability improvement.

			AVERAGE APPROACH			MARGINAL APPROACH		
Resource	Nameplate MW	Cost ($/MW-Day, Nameplate)	ELCC %	UCAP MW	Cost ($/UCAP)	ELCC %	UCAP MW	Cost ($/UCAP)
Resource X	100	$50	40%	40 MW	$125	20%	20 MW	$250
Resource Y	25	$150	80%	20 MW	$187.50	80%	20 MW	$187.50

Aligns the accredited value with expected performance during high-risk hours in operations (which is necessarily on the margin)

Illustrative Example (solely intended to show the concept and not represent future outcomes)

- Assume a resource mix and level of solar penetration that has resulted in expected hours of load shed risk shifting entirely into the evening hours after the sun has set.
- The marginal ELCC of solar in this scenario will be zero (next MW of nameplate solar provides no reduction in load shed risk given all risk occurring outside of solar performance hours).
- Suppose average ELCC of solar is 10% in this scenario, such that every MW nameplate of solar is accredited 0.1 MW of capacity value or UCAP.
- Marginal accredited value (and compensation) is consistent with expected performance of solar resources during the high-risk hours for that year and given portfolio.
- Average accredited value is above the expected performance level of solar during the high-risk hours.

This systematic misalignment results in expected net penalties for solar resources.

		AVERAGE APPROACH		MARGINAL APPROACH	
Resource	Nameplate	ELCC %	UCAP MW	ELCC %	UCAP MW
Solar X	1	10%	0.1 MW	0%	-

Allows for a substitutable product definition where accredited capacity/UCAP can be exchanged on the margin with no expected change in reliability

Illustrative Example: Assume the reliability metric used in accreditation is Expected Unserved Energy (EUE) in MWh.

- Suppose perfect capacity provides an incremental reliability improvement (reduction in EUE) of 20 MWh.
  i.e., 1 MW nameplate of perfect capacity has a marginal reliability impact of 20 MWh EUE.
- Suppose Resource X has an average ELCC of 40% and marginal ELCC of 20%.
  The incremental reliability value is 20% that of perfect capacity (reduction in EUE of 4 MWh per nameplate MW).
- Suppose Resource Y has an average and marginal ELCC of 80%.
  The incremental reliability value is 80% that of perfect capacity (reduction in EUE of 16 MWh per nameplate MW).

- Under average, exchanging 1-for-1 UCAP MW between Resources X and Y can impact reliability.
  - Resource X: 2 nameplate MW = 0.8 MW UCAP; Incremental reliability impact = 2x (4 MWh EUE) = 8 MWh EUE
  - Resource Y: 1 nameplate MW = 0.8 MW UCAP; Incremental reliability impact = 16 MWh EUE
  - Exchange of UCAP results in different changes to reliability
- Under marginal, exchanging 1-for-1 UCAP MW between Resources result in same reliability.
  - Resource X: 4 nameplate MW = 0.8 MW UCAP; Incremental reliability impact = 4x (4 MWh EUE) = 16 MWh EUE
  - Resource Y: 1 nameplate MW = 0.8 MW UCAP; Incremental reliability impact = 16 MWh EUE
  - Exchange of UCAP results in equivalent impact on reliability

Benefits of having a 1-for-1 exchange rate for UCAP MW:
- Improves fungibility of the product
- Provides the same compensation to individual resources that provide the same improvement to system reliability

		AVERAGE APPROACH		MARGINAL APPROACH	
Resource	**Nameplate**	**ELCC %**	**UCAP MW**	**ELCC %**	**UCAP MW**
Resource X	2	40%	0.8 MW	20%	0.4 MW
Resource Y	1	80%	0.8 MW	80%	0.8 MW

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
PJM Interconnection, L.L.C.	)	**Docket No. ER24-__-000**
	)	
	)	

VERIFICATION

I, Dr. Walter Graf, pursuant to 28 U.S.C. § 1746, state, under penalty of perjury, that I am the Walter Graf referred to in the foregoing document entitled "Affidavit of Dr. Walter Graf on Behalf of PJM Interconnection, L.L.C.," that I have read the same and am familiar with the contents thereof, and that the facts set forth therein are true and correct to the best of my knowledge, information, and belief.

/s/ Walter Graf
Walter Graf
Chief Economist
PJM Interconnection, L.L.C.

Dated: October 13, 2023