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The Honorable Kimberly D. Bose  
Secretary  
Federal Energy Regulatory Commission  
888 First Street, N.E. Room 1A  
Washington, D.C. 20426

Re: *PJM Interconnection L.L.C., Docket No. ER21-2582-000*  
*Revisions to Application of Minimum Offer Price Rule*

Dear Secretary Bose,

Pursuant to section 205 of the Federal Power Act (“FPA”),<sup>1</sup> and part 35 of the Federal Energy Regulatory Commission’s (“FERC” or the “Commission”) regulations,<sup>2</sup> PJM Interconnection, L.L.C. (“PJM”) hereby submits for filing proposed revisions to PJM’s Open Access Transmission Tariff (“Tariff”)<sup>3</sup> to reform the application of the Minimum Offer Price Rule (“MOPR”). The reforms proposed herein would modify today’s expansive MOPR and instead return the MOPR to its original purpose by focusing on prohibiting and mitigating the exercise of buyer-side market power. The focused MOPR also includes procedures (including Commission review) to mitigate potential impacts on the capacity auction clearing prices from state programs or policies that condition receipt of benefits on certain bidding behavior (“Conditioned State Support”).

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<sup>1</sup> 16 U.S.C. § 824d.

<sup>2</sup> 18 C.F.R. part 35.

<sup>3</sup> The Tariff is currently located under PJM’s “Intra-PJM Tariffs” eTariff title. *See PJM Interconnection, L.L.C. - Intra-PJM Tariffs*, <https://etariff.ferc.gov/TariffBrowser.aspx?tid=1731> (last visited July 29, 2021). Terms not otherwise defined herein shall have the same meaning as set forth in the Reliability Assurance Agreement (“RAA”), the Tariff, and the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. (“Operating Agreement”).

As discussed herein, the proposed Tariff changes will be effective beginning with the Base Residual Auction associated with the 2023/2024 Delivery Year. As such, PJM respectfully requests an effective date of September 28, 2021, for the proposed Tariff revisions.

## **I. INTRODUCTION AND SUMMARY**

By this filing, PJM proposes to replace the Expanded MOPR<sup>4</sup> ordered by the Commission in December 2019,<sup>5</sup> as well as the previously existing legacy MOPR, with a focused MOPR described in detail below. The Commission has ample grounds for a course correction on the MOPR. As PJM shows in this filing, the Expanded MOPR:

- ignores that state support for renewable resources has become a well-established determinant of supply in the PJM Region, and thus ignores the region's actual supply-demand fundamentals;
- by attempting to “hermetically seal” the capacity market from the reality of state policies that support certain resources, effects an over-correction that itself works against the determination of just and reasonable rates;
- has created substantial conflicts between PJM's capacity market and both state policies and self-supply business models;
- creates a serious risk (already realized in part) for significant loads to be removed from the capacity market altogether;
- threatens to become a mechanism designed primarily for extensive administrative redetermination of supply offers in PJM's capacity auctions, detached from rigorous evaluation of the need for or value of such a broad program of potential administrative determinations;
- foments greater revenue reliance by resources on the capacity market, rather than the energy and reserves markets, contrary to the original design of restructured wholesale electricity markets; and
- is not needed to ensure long-term reliability, as shown by sophisticated multi-decadal modeling of resource investment in the PJM Region.

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<sup>4</sup> The “Expanded MOPR” is the MOPR set forth in Tariff, Attachment DD, section 5.14(h-1).

<sup>5</sup> *PJM Interconnection, L.L.C.*, 169 FERC ¶ 61,239 (2019) (“December 2019 Order”), *order on reh'g & clarification*, 171 FERC ¶ 61,035, *order on reh'g*, 173 FERC ¶ 61,061 (2020), *appeals pending, Ill. Com. Comm'n v. FERC*, Nos. 20-1645, et al. (7th Cir. Apr. 20, 2020).

As also shown in this filing, the Commission has ample grounds to depart from the “Legacy MOPR,” i.e., the distinct set of minimum offer rules directed solely at natural gas-fired resources. That Legacy MOPR is both too narrow, because it applies a non-zero MOPR Floor Price only to new natural gas resources; and too broad, because it can apply to gas-fired resources that do not have both the ability and incentive to effect a material clearing price reduction.

In place of both the Expanded MOPR and the Legacy MOPR, PJM proposes a just and reasonable focused MOPR that:

- accommodates longstanding business models of public power and vertically integrated utilities;
- accommodates state policies on resource mix, so long as they do not attempt to set the price of capacity;
- protects against (1) the Exercise of Buyer-Side Market Power and (2) improper state actions that would have a direct effect on capacity market clearing prices (i.e., Conditioned State Support);
- for Conditioned State Support, applies only to generation resources receiving a state benefit *if the Commission accepts* that the state program or policy would improperly condition such benefit on the resource clearing the market or offering at a specific price; and
- for Exercises of Buyer-Side Market Power, applies only if, upon inquiry into a potential exercise of such power, PJM makes a determination based on evidence that the Capacity Market Seller has the ability and incentive to suppress the capacity auction clearing price, and that such potential price suppression would provide an overall net benefit to an affiliated Load Interest.

Notably, the proposed focused MOPR also enjoys strong stakeholder support. As further explained below, PJM conducted an intensive stakeholder process focused on potential MOPR reform (informed by the Commission’s March 2021 technical conference on resource adequacy<sup>6</sup>) culminating in overwhelming stakeholder endorsement of the

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<sup>6</sup> *Modernizing Electricity Market Design*, Notice of Technical Conference on Resource Adequacy in the Evolving Electric Sector, Docket No. AD21-10-000 (Feb. 18, 2021).

MOPR proposed here by an affirmative sector vote of 4.175 out of 5.

PJM's capacity market remains, and should continue to be, a key part of meeting the resource adequacy needs of the PJM Region. To ensure the continued success of PJM's capacity market, the proposed MOPR reforms contained in this filing will be followed by further PJM stakeholder discussions to examine whether additional reforms are needed to ensure that the PJM Region is able to get the reliability value from each Capacity Resource. To that end, PJM is initiating a comprehensive review of the capacity market rules to ensure the continued reliability of the PJM system given the evolution of the PJM Region's resource mix and taking account of these proposed MOPR reforms. That review of the capacity market components includes, but is not limited to:

- aspects related to the appropriate level of capacity procurement;
- qualification and performance requirements of Capacity Resources;
- clean capacity/energy auctions as an option to allow for procurement of clean resources; and
- potential need for PJM's procurement of additional reliability-based services, with a particular focus on reliability needs in the face of the changing resource portfolio and increased penetration of intermittent resource technologies.<sup>7</sup>

## **II. HISTORY AND NEED TO UPDATE EXISTING MOPR**

PJM's capacity market, known as the Reliability Pricing Model ("RPM"), is instrumental in maintaining resource adequacy, improving generator performance, and providing appropriate price signals to all Market Participants. For more than a decade, the Commission recognized the overall value of the capacity market in sending price signals

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<sup>7</sup> See PJM Board Letter *Regarding Capacity Market Minimum Offer Price Rule and Initiation of the Critical Issue Fast Path Process*, PJM Interconnection, L.L.C., (Apr. 6, 2021), <https://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/20210406-board-letter-regarding-capacity-market-minimum-offer-price-rule-and-initiation-of-the-critical-issue-fast-path-process.ashx> ("April 6, 2021 PJM Board Letter").

to incentivize resource efficiency and innovation.<sup>8</sup> Starting with the 2006 settlement agreement that established the initial RPM market design,<sup>9</sup> the Commission approved the use of a MOPR essentially as a guardrail to protect against the potential exercise of buyer-side market power that may be viewed as presenting a significant threat to market efficiency. In this way, the original market design and the various changes along the path, balanced the need for the capacity market to send accurate price signals with state interests—including public policy objectives and the regulation of their utilities.

However, in December of 2019, after consideration of PJM’s filing to expand MOPR to reach certain select resources,<sup>10</sup> the Commission ordered a significantly greater expansion of MOPR to cover a much larger set of state actions.<sup>11</sup> The 2019 MOPR (i.e., the “Expanded MOPR”) also found certain business models, such as public power, to be a subsidy which could trigger the MOPR.<sup>12</sup>

As further explained below, the Expanded MOPR disrupts the careful balance that had previously worked to accommodate the interests of states and integrated utilities, with appropriate guardrails, while maintaining the integrity of the market and ensuring a

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<sup>8</sup> The price signal also provides valuable information to existing resources, letting them know when it is time to invest and when it is time to retire. *See, e.g., PJM Interconnection, L.L.C.*, 163 FERC ¶ 61,236, at P 156 (2018) (“June 2018 Order”) (recognizing that the capacity market sends “price signals on which investors and consumers rely to guide the orderly entry and exit of capacity resources”); *PJM Interconnection, L.L.C.*, 155 FERC ¶ 61,157, at P 80 (2016) (“Capacity market clearing prices reflecting locational price adders send price signals to encourage capacity investment where it is most valuable.”).

<sup>9</sup> *PJM Interconnection, L.L.C.*, Settlement Agreement and Explanatory Statement of the Settling Parties Resolving All Issues, Docket Nos. ER05-1410-000, -001, and EL05-148-000, -001, at section II.J and Explanatory Statement, Attachment E (Supplemental Affidavit of Robert B. Stoddard) ¶¶ 8-19; *PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,331, at PP 103-104 (2006), *order on reh’g & clarification*, 119 FERC ¶ 61, 318 (2007).

<sup>10</sup> *See* December 2019 Order at P 6.

<sup>11</sup> *See* December 2019 Order at P 37.

<sup>12</sup> *See* December 2019 Order at PP 12, 202-204.

wholesale rate in the zone of reasonableness. After having direct experience reviewing numerous state programs and over three hundred unit-specific exception requests for the May 2021 Base Residual Auction, and in light of the overwhelming stakeholder support for the proposed Tariff changes, reforms to the existing MOPR are now appropriate for consideration by the Commission under its well-settled section 205 standard of review.

***A. The Expanded MOPR Is Unsustainable in the Current Context of the PJM Region.***

Under the Expanded MOPR, any Capacity Market Seller of a Capacity Resource that receives or is entitled to receive any form of State Subsidy, no matter the size of such subsidy, is required to submit a Sell Offer greater than or equal to the applicable MOPR Floor Offer Price for such resource.<sup>13</sup> By casting a net that is so wide, PJM's Expanded MOPR is overly broad and is no longer limited to mitigating against the potential exercise of buyer-side market power. Instead, the Expanded MOPR has become a mechanism designed primarily for extensive administrative redetermination of supply offers in PJM's capacity auctions, detached from rigorous evaluation of the need for or value of such a broad program of potential administrative determinations. This has created unnecessary conflicts between PJM's capacity market and state resource policies. Those conflicts have the potential to cause significant loads to be removed from the capacity market altogether and can erode the fundamental purpose of a centralized capacity market to provide, among other things, market efficiencies and an accurate price signal both for investment and retirement decisions so that capacity can be provided at least cost to consumers.

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<sup>13</sup> Tariff, Attachment DD, section 5.14(h-1).

1. *The Expanded MOPR Ignores that State Support for Renewable Resources Has Become a Well-Established Determinant of Supply in the PJM Region, and Thus Ignores the Actual Supply-Demand Fundamentals.*

PJM’s 2018 MOPR Filing showed in detail the scope and extent of state policies in the PJM Region to support certain resource types—particularly renewable and nuclear resources.<sup>14</sup> Three years on, that policy support has only been expanded and extended.<sup>15</sup> Thus, irrespective of the MOPR, there is scant prospect that states in the PJM Region will discontinue their programs that lend financial support to resources that advance the states’ energy and other policy goals. In other words, the Expanded MOPR has little chance of deterring state subsidy programs.

While PJM cited the aforementioned data in 2018 to argue for expanding MOPR to new resources in conditions when there was a substantial chance of adverse effects on wholesale capacity prices,<sup>16</sup> the ensuing experience brings a fresh perspective. Rather than a threat to be counteracted, state policies supporting certain resources within the PJM Region are a reality to be acknowledged. Moreover, as the U.S. Supreme Court has observed, FERC’s responsibility to ensure just and reasonable rates was never designed to

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<sup>14</sup> *PJM Interconnection, L.L.C.*, Capacity Repricing or in the Alternative MOPR-Ex Proposal: Tariff Revisions to Address Impacts of State Public Policies on the PJM Capacity Market, Docket No. ER18-1314-000, at 25-28 (Apr. 9, 2018) (“2018 Capacity Repricing Filing”).

<sup>15</sup> See, e.g., Virginia Clean Economy Act, HB 1526, 2020 Sess. (Va. 2020) (adopting a renewable portfolio standard that requires Phase 1 utilities to generate 100% of their power from renewable resources by 2045); An Act to Amend Title 26 of the Delaware Code Relating to Renewable Energy Standards, S.B. 33, 151st Gen. Assembly (Del. 2021) (increasing and extending state renewable portfolio standard to 40% renewable resources, including 10% solar photovoltaic resources, by 2035); Clean Energy DC Omnibus Amendment Act of 2018, D.C. Act 22-583 D.C. 2019) (increasing and extending state renewable portfolio standard to 100% tier 1 renewable resources, including 10% solar photovoltaic resources, by 2041); Maryland Clean Energy Jobs Act of 2019, S.B. 516, 2019 Sess. (Md. 2019) (increasing and extending state renewable portfolio standard to 50% tier 1 renewable resources, including 14.5% solar photovoltaic resources, by 2030).

<sup>16</sup> 2018 Capacity Repricing Filing at 25-28.

be “hermetically sealed” from the impact of state actions.<sup>17</sup> In fact, today’s state policies are often designed to address externalities that are not accounted for in PJM’s wholesale markets, a reality which the Court in *Hughes* readily acknowledged is not necessarily in conflict with federal law.<sup>18</sup> As PJM’s Senior Director of Economics Dr. Walter Graf, explains, “such policies can be entirely supported on economic grounds as welfare-enhancing [and] . . . even if they have the ancillary effect of lowering market prices, there is no reason to suspect that they represent an exercise of buyer-side market power.”<sup>19</sup>

The Expanded MOPR, however, does not acknowledge that reality, and instead produces its own set of problems. First among these is its expanded potential for pricing out resources from the capacity market, and then ignoring those resources when committing capacity for the region. The Expanded MOPR tests for whether a state-subsidized Capacity Resource offer is below a competitive level and—if it is—resets the offer to a higher level that excludes the economic benefit of any state support or subsidy. If that higher offer price does not clear the auction, the resource is not committed to provide capacity to the PJM Region, and its capacity is not counted towards meeting reliability requirements in PJM. But if the resource is installed (or remains in service) and effectively provides a reliability service notwithstanding denial of capacity revenues, the auction presents an incorrect view of both the price and quantity of providing reliability service in PJM.<sup>20</sup>

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<sup>17</sup> *FERC v. Elec. Power Supply Ass’n*, 136 S. Ct. 760, 776 (2016).

<sup>18</sup> *Hughes v. Talen Energy Mktg., LLC*, 136 S. Ct. 1288 (2016).

<sup>19</sup> Affidavit of Dr. Walter F. Graf on Behalf of PJM Interconnection, L.L.C. (Attachment E) ¶ 17 (“Graf Aff.”).

<sup>20</sup> PJM’s 2018 MOPR Proposal did admittedly have a similar effect and was widely criticized as a result. However, PJM limited the reach of its MOPR to only reach those actions that had a significant impact on market clearing prices and also addressed the potential over-procurement issue by allowing those subsidized



By casting a wide net, and potentially increasing the size of that parallel set of excluded but installed resources, the Expanded MOPR poses a threat of a greater departure from the reality of the resource base that supports PJM Region reliability objectives. Importantly, the excluded resources meet all technical and substantive eligibility requirements for Capacity Resources. Their potential exclusion is based solely on the requirement to offer at or above the applicable MOPR floor offer price, and not on any inability to provide a qualifying contribution to PJM Region reliability.

In such cases, as Mr. Keech explains, the Expanded MOPR results in a price signal for an increment of added capacity that is not needed, given that the excluded resource will be in service.<sup>21</sup> At the same time, the excluded resource would, in all likelihood, continue to provide capacity value even though it may not have received a capacity commitment because such resources are generally low-variable cost resources that will operate whenever possible.<sup>22</sup> This ultimately results in consumers in the states where the subsidies originated in paying twice, i.e., for both the excluded resource and the resource committed through the auction because the excluded resource did not clear.<sup>23</sup> Indeed, as Mr. Keech notes, even customers that do not directly bear the costs of the excluded resource in their state-approved rates may still see a capacity cost increase, when (as would be expected) the auction commits a resource that had a higher Sell Offer than the excluded resource's

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resources to clear in the market. In the December 2019 Order, the Commission rejected that part of PJM's proposal and ordered a far more sweeping MOPR that substantially exacerbated the 'paying twice' issue outlined above. *See* December 2019 Order at PP 6-17.

<sup>21</sup> Affidavit of Adam J. Keech on Behalf of PJM Interconnection, L.L.C. (Attachment D) ¶ 11 ("Keech Aff.").

<sup>22</sup> *Id.*

<sup>23</sup> *Id.*

original offer.<sup>24</sup>

Conversely, as Mr. Keech explains, leaving the excluded resource in the auction and allowing it to clear would send a lower price signal that is consistent with supply and demand fundamentals, given that the resource is (or will be) in service for the Delivery Year, and will be supporting reliability.<sup>25</sup> Likewise, the price would be consistent with the marginal cost of capacity when considering all relevant revenue streams that resources receive. Whether they are viewed to be acceptable, beneficial, detrimental, or otherwise, out-of-market revenues to resources are still revenues that are collected that do not need to be recollected in the capacity market. Application of the MOPR to any out-of-market revenue stream just because it is out-of-market requires a resource to offer at a level that suggests they need to collect the subsidy revenues they are already collecting again. This offer level is inconsistent with the level of revenues that the resource truly needs to collect from the capacity market and therefore inconsistent with the marginal cost of providing capacity.<sup>26</sup>

Further, as Dr. Graf explains, while state policies favoring certain generation resources may ultimately cause a reduction in capacity clearing prices, such an outcome “should not be interpreted as a harmful secondary impact of one state’s policies on other states. Rather, the reduction in prices is a natural consequence of the PJM market appropriately reflecting state policies and customer preferences for certain types of resources. Such state subsidies only lower total costs for consumers in other states.”<sup>27</sup>

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<sup>24</sup> *Id.*

<sup>25</sup> *Id.*

<sup>26</sup> *Id.*

<sup>27</sup> Graf Aff. ¶ 17 n.3.

As Mr. Keech further explains, if, due to the extensive scope of the Extended MOPR, capacity prices do not reflect actions taken by states and by Self-Supply Entities to support resources that the Expanded MOPR excludes from the auction, then capacity prices will incentivize resources to be built that are not needed to maintain reliability. If the entities taking these actions remain in the capacity market, the market will produce prices that do not reflect actual supply and demand fundamentals. If investors respond to such inaccurate price signals, the results will be systematic over-procurement. Indeed, as discussed below, Professor Peter Cramton's analysis, performed using his detailed model of the PJM capacity, energy, and reserves markets, shows that the Expanded MOPR "results in more resources and more expense for consumers."<sup>28</sup> While Professor Cramton's analysis does not show a dramatic difference in resource entry and exit decisions over a multi-decade period, it does show that the Expanded MOPR would result in higher costs to consumers in states where the subsidies originate due to excluding resources that provide reliability from the capacity market.<sup>29</sup>

In short, state economic support for policy-favored resources is now a reality of the supply of resources in the PJM Region, having been countenanced by relevant state authorities. The capacity market's exclusion of the subsidized set of resources as a result of the Expanded MOPR must be amended to restore price signals that are more consistent with the reality of supply and demand fundamentals as a result of state actions. To continue to apply the Expanded MOPR would attempt to "hermetically seal" the capacity market

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<sup>28</sup> Affidavit of Peter Cramton on Behalf of PJM Interconnection, L.L.C. (Attachment C) ¶ 74 ("Cramton Aff.").

<sup>29</sup> Cramton Aff. ¶ 74.

from the reality of state actions—a path which is not sustainable and an over-correction that itself works against the determination of just and reasonable rates.

2. *The Expanded MOPR Incentives Capacity Market Withdrawal that Is More Harmful to the Capacity Market than the Conduct the Expanded MOPR Attempts to Address.*

As explained above, the Expanded MOPR’s broad reach and expanded definition of subsidies poses an increased risk that resources receiving such perceived subsidies will not clear the market, resulting in either (1) frustration of the state policy objective or Load Serving Entity (“LSE”) resource strategy; or (2) customer payment for duplicative resources. A fundamental flaw in the Expanded MOPR is that affected parties will find this risk intolerable. As Mr. Keech explains, the evidence indicates that states and Self-Supply entities are more likely to exit the capacity market to meet their policy and business objectives, rather than remain in the capacity market and curtail those objectives.<sup>30</sup>

Indeed, one market participant with major load serving responsibility in the PJM Region, Virginia Electric and Power Company, a subsidiary of Dominion Resources, Inc., chose to exit the capacity market, by electing the Fixed Resource Requirement Alternative (“FRR”),<sup>31</sup> rather than participate in the May 2021 Base Residual Auction.<sup>32</sup> Dominion’s election of the FRR Alternative is a direct result of the ramifications associated with the current Expanded MOPR that became effective with the 2022/2023 Delivery Year.<sup>33</sup> In

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<sup>30</sup> Keech Aff. ¶ 8.

<sup>31</sup> RAA at Article 1 – Definitions (Fixed Resource Requirement Alternative or FRR Alternative) & Schedule 8.1 (Fixed Resource Requirement Alternative).

<sup>32</sup> Rich Heidorn Jr., *Dominion Opts out of PJM Capacity Auction*, RTO Insider (May 5, 2021), [www.rtoinsider.com/articles/20192-dominion-opts-out-of-pjm-capacity-auction](https://www.rtoinsider.com/articles/20192-dominion-opts-out-of-pjm-capacity-auction) (Dominion spokesman quoted as stating “[g]iven the minimum offer price rule and the Virginia Clean Economy Act [VCEA] requirements, FRR is a cost-effective choice on behalf of our customers”).

<sup>33</sup> Keech Aff. ¶ 8; *see also* Rich Heidorn Jr., *Dominion Opts out of PJM Capacity Auction*, RTO Insider (May 5, 2021), <https://www.rtoinsider.com/articles/20192-dominion-opts-out-of-pjm-capacity-auction>; *see also*

addition, as Mr. Keech reports, authorities in New Jersey, Illinois, and Maryland similarly have investigated the best course of action for their respective states going forward, and it is expected those discussions will resume without prompt, meaningful MOPR reform.<sup>34</sup>

As Mr. Keech also explains, when a state, LSE, or Self-Supply Entity takes its entire footprint out of the capacity auction, it effectively results in uneconomic resources receiving a capacity commitment and create further downward pressure on the price.<sup>35</sup> This is because when an entity elects the FRR Alternative, it “generally must do so for 100% of their load based on the current rules. By taking this step, they may be able to meet their renewable objective but because they must meet the remaining . . . obligation through non-market means such as self-supply or bilateral contracts, it is almost a certainty that not all of the remaining . . . load will be served by the most economic resources on the system.”<sup>36</sup>

Confirming this expected impact, the Independent Market Monitor (“IMM”) in 2019 released a report<sup>37</sup> containing analysis that quantified the impact of an FRR election

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Sarah Vogel song,, *Dominion’s exit from regional capacity market raises some eyebrows – and questions*, Virginia Mercury (May 25, 2021), <https://www.virginiamercury.com/2021/05/25/dominions-exit-from-regional-capacity-market-raises-some-eyebrows-and-questions/>.

<sup>34</sup> See *In the Matter of BPU Investigation of Resource Adequacy Alternatives*, Docket No. EO20030203 (Mar. 27, 2020) (the New Jersey Board of Public Utilities is staying its proceeding precisely because it anticipated this filing to replace the Expanded MOPR); Clean Energy Jobs Act, Ill. SB2248, 102nd Gen. Assembly, State of Ill. (Feb. 26, 2021) (introduced by Sen. Collins); Kathleen Spees, et al., *Alternative Resource Adequacy Structures for Maryland*, Maryland Energy Administration (March 2021), <https://energy.maryland.gov/Reports/Alternative%20Resource%20Adequacy%20Structures%20for%20Maryland%20Final%20Brattle%20Study%20March%202021.pdf>.

<sup>35</sup> Keech Aff. ¶ 9.

<sup>36</sup> Keech Aff. ¶ 9.

<sup>37</sup> *Potential Impacts of the Creation of a COMED FRR*, The Independent Market Monitor for PJM (Dec. 18, 2019), [https://www.monitoringanalytics.com/reports/Reports/2019/IMM\\_Potential\\_Impacts\\_of\\_the\\_Creation\\_of\\_a\\_ComEd\\_FRR\\_20191218.pdf](https://www.monitoringanalytics.com/reports/Reports/2019/IMM_Potential_Impacts_of_the_Creation_of_a_ComEd_FRR_20191218.pdf).

by Commonwealth Edison Company. The IMM estimated that Exelon Corporation's departure from the capacity auction would reduce the unconstrained region capacity clearing price by 44.1 percent.<sup>38</sup> In 2021, the IMM released a similar report<sup>39</sup> with various scenarios to quantify the impact of an FRR election for various LSEs in the state of Virginia. That analysis also estimated that the Virginia LSEs' departure from the capacity auction would reduce the unconstrained region capacity clearing price by 35.7 percent.<sup>40</sup>

Thus, removing a sizable fraction of the demand from the capacity auctions (as would happen if one or more states directed their LSEs to elect the FRR Alternative in response to state concerns about the Expanded MOPR's impact on state resource policies and consumer costs) would likely substantially reduce the capacity prices paid to sellers that remain in the auction. As Mr. Keech explains, that estimated capacity price change is much greater than might result if some narrow exercise of buyer-side market power managed to escape mitigation under PJM's proposed MOPR.<sup>41</sup> For example, even an 800

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<sup>38</sup> *Id.* at 1.

<sup>39</sup> *Potential Impacts of the Creation of Virginia FRRs*, The Independent Market Monitor for PJM (May 18, 2021), [https://www.monitoringanalytics.com/Reports/reports/2021/IMM\\_VA\\_FRR\\_Report\\_20210518.pdf](https://www.monitoringanalytics.com/Reports/reports/2021/IMM_VA_FRR_Report_20210518.pdf). ("Virginia FRR Report") See also the IMM's analyses of the potential auction impacts of election of the FRR Alternative by major LSEs. *Potential Impacts of the Creation of Maryland FRRs*, The Independent Market Monitor for PJM (Apr. 16, 2020), [http://www.monitoringanalytics.com/reports/Reports/2020/IMM\\_Potential\\_Impacts\\_of\\_the\\_Creation\\_of\\_Maryland\\_FRRs\\_20200416.pdf](http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of_Maryland_FRRs_20200416.pdf); *Potential Impacts of the Creation of New Jersey FRRs*, The Independent Market Monitor for PJM (May 13, 2020), [https://www.monitoringanalytics.com/reports/Reports/2020/IMM\\_Potential\\_Impacts\\_of\\_the\\_Creation\\_of\\_New\\_Jersey\\_FRRs\\_20200513.pdf](https://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of_New_Jersey_FRRs_20200513.pdf); *Potential Impacts of the Creation of Ohio FRRs*, The Independent Market Monitor for PJM (July 17, 2020), [https://www.monitoringanalytics.com/Reports/Reports/2020/IMM\\_Potential\\_Impacts\\_of\\_the\\_Creation\\_of\\_20Ohio\\_FRRs\\_20200717.pdf](https://www.monitoringanalytics.com/Reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of_20Ohio_FRRs_20200717.pdf); *Potential Impacts of the Creation of District of Columbia FRRs*, The Independent Market Monitor for PJM (May 7, 2021), [https://www.monitoringanalytics.com/reports/Reports/2021/IMM\\_Potential\\_Impact\\_of\\_the\\_Creation\\_of\\_District\\_of\\_Columbia\\_FRR\\_20210507.pdf](https://www.monitoringanalytics.com/reports/Reports/2021/IMM_Potential_Impact_of_the_Creation_of_District_of_Columbia_FRR_20210507.pdf).

<sup>40</sup> Virginia FRR Report at 2.

<sup>41</sup> Keech Aff. ¶ 10.

megawatts (“MW”) unit offered below cost in the Rest of RTO region would have had only a \$0/MW-day price impact on the RTO clearing price in the last auction.<sup>42</sup> In short, the Expanded MOPR exacerbates the very price suppression issue it seeks to mitigate because it can motivate entities to take their entire portfolio out of the capacity auction.<sup>43</sup>

3. *Expanded MOPR Shifts Emphasis Away from Energy Market and to Capacity Market, Which Should Only Be a Supplement to the Energy Market.*

As explained by Professor Cramton, PJM’s capacity market is designed to solve for the “missing money” problem because the energy and reserve markets do not sufficiently yield prices to motivate efficient investments.<sup>44</sup> In this way, PJM’s capacity market is designed to help “to bring adequate resources, coordinate investment, and manage risk.”<sup>45</sup> However, the Expanded MOPR undermines that premise by excluding resources that participate in the energy and reserves markets from the capacity market. While excluded resources contribute to reliability, they are ignored in the capacity market.

Ultimately, these extra resources that are unaccounted for in the capacity market only amplify the missing money problem because “[b]y clearing resources that duplicate resources favored by state policy, the [Expanded] MOPR results in downward pressure on energy prices, the largest source of resource revenues.”<sup>46</sup> This creates a counter-productive feedback as more state-sponsored resources enter the energy market because while “[t]he reserve margin increases, . . . capacity prices rise due to more excluded resources, and spot

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<sup>42</sup> See Graf Aff. ¶ 22.

<sup>43</sup> Keech Aff. ¶ 8.

<sup>44</sup> Cramton Aff. ¶ 25.

<sup>45</sup> Cramton Aff. ¶ 25.

<sup>46</sup> Cramton Aff. ¶ 37.

prices fall.”<sup>47</sup> As a result, “[t]he capacity price no longer reflects the cost of supplying energy during shortage.”<sup>48</sup>

In short, under the Expanded MOPR, when energy resources are excluded from the capacity market, the practical result is excess supply beyond the reserve level cleared in the capacity auction. As Professor Cramton explains, “[t]his shifts revenues from the energy and reserves markets to the capacity market, increasing the role of the capacity revenues in investment decisions.” The result of such an outcome “moves the market further from the ideal where the capacity revenues reflect the financial cost of the obligation to deliver energy and reserves during shortages.”<sup>49</sup>

4. *Professor Cramton’s Sophisticated, Long-Term PJM Region Model Indicates that the Expanded MOPR Is Not Needed to Ensure Reliability.*

The Expanded MOPR rests in part on the theory that subsidized resources will reduce clearing prices below the level needed to ensure that unsubsidized, otherwise economic, resources will clear the auction, thus impairing the PJM capacity auctions’ ability to ensure satisfaction of reliability objectives.<sup>50</sup> However, based on sophisticated modeling by Professor Peter Cramton, a pre-eminent expert on capacity markets, that concern may be overstated.

Professor Peter Cramton tested the impacts of the Expanded MOPR and PJM’s proposed focused MOPR on resource mix, entry and exit from the capacity market. Using

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<sup>47</sup> Cramton Aff. ¶ 11.

<sup>48</sup> Cramton Aff. ¶ 11.

<sup>49</sup> Cramton Aff. ¶ 15.

<sup>50</sup> See June 2018 Order at PP 150-156; December 2019 Order at PP 37-42; *PJM Interconnection, L.L.C.*, 171 FERC ¶ 61,034, at PP 25-34 (2020); *PJM Interconnection, L.L.C.*, 171 FERC ¶ 61,035, at PP 35-46.



the 2019 PJM Region resource mix as a starting point, Professor Cramton’s model examined “the equilibrium entry and exit of resources on an annual basis” and “estimates resource revenues from the capacity, energy, and reserves markets to determine the net present value of entry or exit.”<sup>51</sup> The model included both the day-ahead and real-time markets. Professor Cramton posited two hypothesis to be tested by his analysis:

Hypothesis 1: The PJM market is reliable with either a broad or [focused] MOPR.

Hypothesis 2: The broad MOPR brings more resources to PJM. These extra resources do not make the market more reliable.<sup>52</sup>

The results of Professor Cramton’s analysis of entry and exit over the next two decades (through 2040) are presented graphically in his affidavit.

Based on this analysis, Professor Cramton “conclude[s] that PJM’s proposed MOPR is an essential improvement.”<sup>53</sup> He finds that “[a]lthough both the broad MOPR and [focused] MOPR bring reliability, the broad MOPR results in more resources and more expense for consumers.”<sup>54</sup> That is, there is no reliability difference between the two types of MOPR, but as Professor Cramton states, “the advantage of [focused] MOPR is reduced consumer cost. [Focused] MOPR avoids carrying additional resources that do not contribute to reliability.”<sup>55</sup>

In other words, if the Expanded MOPR is not needed to ensure reliability, and if it does not produce notable efficiency or cost savings relative to PJM’s proposed, more

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<sup>51</sup> Cramton Aff. ¶ 45.

<sup>52</sup> Cramton Aff. ¶ 52.

<sup>53</sup> Cramton Aff. ¶ 73.

<sup>54</sup> Cramton Aff. ¶ 74.

<sup>55</sup> Cramton Aff. ¶ 74.

targeted MOPR, there is little if any justification for the need to continue the adverse consequences of the Expanded MOPR detailed in the preceding subsections.

***B. Other PJM Capacity Market Rules Reasonably Ameliorate the Risk, if Any, of Possible Adverse Outcomes from Moving Beyond the Expanded MOPR.***

*1. The VRR Curve Helps Protect Against Possible Exercise of Buyer-Side Market Power.*

PJM’s Variable Resource Requirement (“VRR”) curve has been shown to be effective in interacting with the supply curve to yield just and reasonable rates.<sup>56</sup> Indeed, the VRR curve itself is a guardrail against market power in that it ensures the correct price signal is sent when supply is below the Installed Reserve Margin (“IRM”) and provides an important price signal greater than zero when supply is greater than the IRM.<sup>57</sup> Professor Cramton explains that a “downward-sloping demand curve also weakens the incentive to exercise market power.”<sup>58</sup> Unlike a vertical demand curve, which “creates incentives for the buyer to expand supply to push the capacity price to the price floor,” a “sloped demand curve mitigates both incentives,” because supply changes along a downward-sloping demand curve “have a more modest impact on the capacity price” relative to a vertical curve. Accordingly, PJM’s VRR curve already contributes toward dissuading the exercise of buyer-side market power.

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<sup>56</sup> See, e.g., *PJM Interconnection, L.L.C.*, 119 FERC ¶ 61,318, at PP 99-109 (2007) (explaining why the VRR curve results in just and reasonable rates at differing levels of supply).

<sup>57</sup> See *PJM Interconnection, L.L.C.*, 128 FERC ¶ 61,157, at P 41 (2009) (“Cleared capacity can exceed the target in some periods and fall short of it at other times. But in order for the RPM auction mechanism to achieve its reliability objectives, the demand curve needs to be properly set to reflect the actual costs of a new entrant.” (footnote omitted)); *PJM Interconnection, L.L.C.*, 149 FERC ¶ 61,183, at P 52 (2014) (“[W]e find persuasive PJM’s argument that the proposed VRR Curve is reasonably needed for PJM to achieve an acceptable level of reliability, given evolving market conditions.”).

<sup>58</sup> Cramton Aff. ¶ 30.

2. *The Expanded MOPR Does Not Account for the Changed Circumstances Associated with PJM’s Expected Imminent Implementation of Rules that Will Significantly Affect the Capacity Contribution from Renewable Resources.*

The Expanded MOPR also fails to account for the likely imminent implementation of PJM’s Effective Load Carrying Capacity (“ELCC”) rules. As Mr. Keech points out, “ELCC will right-size the capacity accreditation for wind, solar and storage, and in doing so will also mitigate price impacts of continued growth of these asset classes.”<sup>59</sup> PJM’s 2018 MOPR filing, and the Commission’s ensuing finding that PJM’s pre-existing MOPR was unjust and unreasonable, both rested on an assumption that the capacity quantity and price impact of renewables would become increasingly significant going forward.<sup>60</sup>

ELCC requires this assumption to be revisited. ELCC will tend to reduce the capacity value of intermittent resources as their penetration increases. That major effect of ELCC will in turn limit the capacity auction price impacts of intermittent resources, which means that the projected increase, as of 2018, of the auction impact of these resources was likely overstated.<sup>61</sup>

3. *The MOPR Rule Specific to Certain Gas-Fired Resources Also Should Be Superseded.*

The December 2019 Order also carried forward a distinct set of rules that generally apply a non-zero MOPR Floor Offer Price only to new natural gas resources by default.<sup>62</sup> As Mr. Keech explains for this “legacy MOPR,” “[t]he specific circumstances around the

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<sup>59</sup> Keech Aff. ¶ 13.

<sup>60</sup> See 2018 Capacity Repricing Filing at 24-28; December 2019 Order at P 37; Keech Aff. ¶ 13.

<sup>61</sup> Keech Aff. ¶ 13.

<sup>62</sup> December 2019 Order at P 42. That natural gas MOPR provisions (i.e., the “Legacy MOPR”) are contained in Tariff, Attachment DD, section 5.14(h).

resource are not consequential to the application of the MOPR. If it is a new natural gas resource, it is subject to MOPR.”<sup>63</sup> The Legacy MOPR rested in part on an assumption that a new natural gas resource would be the exclusive vehicle by which an entity would seek to exercise buyer-side market power.<sup>64</sup>

The Commission has ample basis to supersede this Legacy MOPR as part of its acceptance of PJM’s proposed, more targeted MOPR. PJM’s proposal will address buyer-side market power if and when the owner of any resource type tries to exercise such power; there is no need for rules specific to gas-fired plants. Moreover, as Mr. Keech explains, the Legacy MOPR is overly broad in that it mitigates all new natural gas resources offers, even those from Capacity Market Sellers that would otherwise be expected to submit offers reflecting their economic net costs, such as merchant sellers that are not receiving out-of-market payments and that are not engaged in inappropriate bilateral contracts.<sup>65</sup>

### **III. PJM PROPOSES A NEW, MORE FOCUSED MOPR TO PROTECT THE MARKET FROM BUYER-SIDE MARKET POWER AND STATE ACTIONS THAT DIRECTLY INTERFERE WITH THE AUCTION CLEARING OUTCOMES, WHILE ACCOMMODATING STATE PUBLIC POLICIES AND SELF-SUPPLY MODELS**

PJM proposes to replace the Legacy MOPR and the Expanded MOPR with a more focused MOPR, starting with the 2023/2024 Delivery Year.<sup>66</sup> As discussed below, PJM’s

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<sup>63</sup> Keech Aff. ¶ 14.

<sup>64</sup> *Id.*

<sup>65</sup> Keech Aff. ¶ 15.

<sup>66</sup> PJM is not proposing to replace the Legacy MOPR or the Expanded MOPR for the RPM Auctions associated with the 2022/2023 Delivery Year given that it would be inconsistent to conduct capacity auctions for the same Delivery Year under different rules. In practice, this means that the Third Incremental Auction associated with the 2022/2023 Delivery Year will be conducted under the Legacy MOPR and Expanded MOPR provisions. To effectuate the sunseting of these MOPRs with the 2022/2023 Delivery Year, PJM is proposing to add a sentence at the beginning of each MOPR stating that “The provisions of this section 5.14(h) [or 5.14(h-1)] shall not be effective after the 2022/2023 Delivery Year.” Accordingly, under PJM’s proposal, none of the elements of the Legacy or Expanded MOPR will be operative after May 31, 2023, the end of that Delivery Year. In addition, PJM is removing the rule penalizing resources that elected the

proposal is just and reasonable. That is all that need be shown for acceptance of PJM's proposal under FPA section 205.<sup>67</sup> In particular, PJM does not need to show that the current effective MOPR is unjust and unreasonable.<sup>68</sup> But, as explained above and in the affidavits of Mr. Keech and Professor Cramton, there are significant flaws in the existing Legacy and Expanded MOPRs. The elimination of those flaws lends further support to PJM's proposal to adopt a much more targeted MOPR. Their showings also make clear that the Commission would be well justified, in this instance, in "adapt[ing] [its] rules and policies to the demands of changing circumstances."<sup>69</sup>

While PJM's capacity market does not require the Expanded MOPR's broad protection from price suppression to ensure just and reasonable outcomes, that does not mean the market does not require a MOPR. Rather, as Mr. Keech testifies, the market still requires a MOPR, but it need only protect the market from actions that improperly affect the market clearing price.<sup>70</sup> The Legacy MOPR by itself does not provide sufficient protection because, as Mr. Keech explains, it "only applies a non-zero MOPR Floor Price

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competitive exemption under the Expanded MOPR and accepts a State Subsidy for the 2022/2023 Delivery Year, as it is inconsistent with the premise of the focused MOPR. *See* proposed Tariff, Attachment DD, section 5.14(h-1)(4)(B). The Tariff will still explicitly prohibit resources that elected the competitive exemption from accepting a State Subsidy. *Id.*

<sup>67</sup> *See PJM Interconnection, L.L.C.*, 147 FERC ¶ 61,103, at P 59 (2014) ("In submitting proposed tariff changes pursuant to a FPA section 205 filing, PJM need only demonstrate that its proposed revisions are just and reasonable, not that its proposal is the most just and reasonable among all possible alternatives."); *see also Cities of Bethany v. FERC*, 727 F.2d 1131, 1136, (D.C. Cir. 1984).

<sup>68</sup> *City of Winfield v. FERC*, 744 F.2d 871, 877 (D.C. Cir., 1984) ("The statutory obligation of the utility [under FPA section 205], however, is not to prove the continued reasonableness of unchanged rates or unchanged attributes of its rate structure. . . . It did not have the burden of proving the justness and reasonableness of the method of average cost rates already in place. Its burden in that regard was merely to justify the increase in those rates over the existing rates.").

<sup>69</sup> *ISO New England Inc.*, 143 FERC ¶ 61,150, at P 198 (2013) (citing *In re Permian Basin Area Rate Cases*, 390 U.S. 747, 784 (1968)), *order on reh'g*, 150 FERC ¶ 61,209 (2015), *petition denied sub nom. Emera Maine v. FERC*, 854 F.3d 662, 670, (D.C. Cir. 2017) ("This case presents another example of changing circumstances and an appropriate adaptation of rules and policies by FERC.").

<sup>70</sup> Keech Aff. ¶ 16.

to new natural gas resources by default”<sup>71</sup> and thus is too limited of a tool when it comes to a screen and rules to mitigate buyer-side market power.<sup>72</sup> Accordingly, PJM proposes a MOPR that applies to all generation resource types and protects against (1) the actual Exercise of Buyer-Side Market Power and (2) improper state actions that would have a direct effect on capacity market clearing prices. As Mr. Keech explains, “[b]oth such types of actions are plainly impermissible should not be permitted to have a detrimental effect the market.”<sup>73</sup> Mitigating the impact of these two influences on the capacity market on a technology neutral basis is appropriate. Thus, PJM’s proposed MOPR will contribute toward a just and reasonable, and importantly sustainable, market structure and ensure capacity commitments and clearing prices are aligned with underlying supply and demand fundamentals.

Notably, while a MOPR is still needed to prevent the potential Exercise of Buyer-Side Market Power, a market mitigation provision for Buyer-Side Market Power does not need to be commensurate with seller side market power rules because as Dr. Walter Graf explains, “Buyer-Side Market Power is not symmetrical to supplier-side market power in the PJM capacity market.”<sup>74</sup> More particularly, supplier-side market power “is exercised by economic or physical withholding supply of capacity.” In contrast, “buyers with the ability and incentive to suppress prices cannot symmetrically and directly withhold demand for capacity from the market, as demand is determined through an administrative demand

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<sup>71</sup> Keech Aff. ¶ 14.

<sup>72</sup> Keech Aff. ¶ 15 (citing December 2019 Order).

<sup>73</sup> Keech Aff. ¶ 16.

<sup>74</sup> Graf Aff. ¶ 10.

curve.”<sup>75</sup> Thus, “[b]ecause buyers cannot use demand withholding to favorably affect market prices, participants with buyer-side market power instead must offer an uneconomic resource (i.e., a resource that generally would not clear the market) sufficiently below its economic cost that it does clear, [and] displace more expensive (but economic) resources, and [thereby] lowers the clearing price.”<sup>76</sup> To that end, the proposed provisions relating to Buyer-Side Market Power, including the self-certification requirement described below, are only appropriate for MOPR purposes and would not be appropriate if applied to seller side market power mitigation rules.

**A. *Introduction to the Focused MOPR.***

PJM is proposing a more focused MOPR to ensure that the Reliability Pricing Model continues to produce just and reasonable outcomes. In so doing, the MOPR will no longer mitigate all forms of state subsidies, most of which were never designed to incentivize or require a Capacity Market Seller to exercise buyer side market power. As explained above, the Expanded MOPR created more problems than it was intended to solve. All of the described adverse consequences demonstrate the need to replace the Expanded MOPR with the new MOPR proposed herein.

Under PJM’s proposed focused MOPR, Sell Offers that would actually be deemed an Exercise of Buyer-Side Market Power would be subject to the MOPR. PJM is proposing to define this term in the Tariff as “anti-competitive behavior” by a Capacity Market Seller with a Load Interest of any kind, i.e., a “responsibility for serving load within the PJM Region,” whether through its own load service obligations, that of an affiliate, or through

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<sup>75</sup> Graf Aff. ¶ 10.

<sup>76</sup> Graf Aff. ¶ 10.

a contractual arrangement with a LSE<sup>77</sup> “for the overall benefit of the Capacity Market Seller’s (and/or affiliates of Capacity Market Seller) portfolio of generation and load or that of the directing entity with a Load Interest.”<sup>78</sup> Thus, only Generation Capacity Resources of Capacity Market Sellers with a “Load Interest”<sup>79</sup> could be subject to the MOPR based on buyer-side market power concerns.<sup>80</sup> The process and tests for determining whether a resource may be used in an Exercise of Buyer-Side Market Power, and thus would be subject to the MOPR, are discussed below.

With respect to state actions, as Lisa Morelli, PJM’s Director of Market Design explains, PJM’s focused MOPR will generally accommodate both state policies regarding generation resource mix and the long-standing business models of public power entities.<sup>81</sup> However, accommodation of state resource mix policies cannot be boundless. The capacity market must have guardrails to protect it from actions by the state or by sellers with Load Interests that would improperly intrude on the wholesale market-clearing price. Specifically, the capacity market cannot accommodate state policies that provide state

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<sup>77</sup> Proposed Tariff, Definitions – L-M-N (Load Interest).

<sup>78</sup> Proposed Tariff, Definitions – E-F (“‘Exercise of Buyer-Side Market Power’ shall mean anti-competitive behavior of a Capacity Market Seller with a Load Interest, or directed by an entity with a Load Interest, to uneconomically lower RPM Auction Sell Offer(s) in order to suppress RPM Auction clearing prices for the overall benefit of the Capacity Market Seller’s (and/or affiliates of Capacity Market Seller) portfolio of generation and load or that of the directing entity with a Load Interest as determined pursuant to Tariff, Attachment DD, section 5.14(h-2)(2)(B). A bilateral contract between the Capacity Market Seller and an entity with a Load Interest with the express purpose of lowering capacity market clearing prices shall be evidence of the Exercise of Buyer-Side Market Power.”).

<sup>79</sup> PJM proposes to define Load Interest as having “responsibility for serving load within the PJM Region, whether by the Capacity Market Seller, an affiliate of the Capacity Market Seller, or by an entity with which the Capacity Market Seller is in contractual privity with respect to the subject Generation Capacity Resource.”

<sup>80</sup> To be clear, this definition applies only to the potential exercise of *buyer-side* market power and in no way should not be interpreted as defining seller-side market power.

<sup>81</sup> Affidavit of Lisa Morelli on Behalf of PJM Interconnection, L.L.C. (Attachment F) ¶ 7 (“Morelli Aff.”).



support conditioned on seller offer behavior that would directly affect the clearing price. Such state policies and Exercises of Buyer-Side Market Power improperly interfere with the auction-clearing price. Indeed, the U.S. Supreme Court has found that “condition[ing] payment of funds on capacity clearing the auction” to be a “fatal defect,”<sup>82</sup> because that “improperly sets the rate [a seller] receives for interstate capacity sales to PJM.”<sup>83</sup>

Accordingly, PJM is proposing to apply the MOPR to Sell Offers based on resources that receive “Conditioned State Support,” which is defined as “any financial benefit required or incentivized by a state, or political subdivision of a state acting in its sovereign capacity, provided outside of PJM markets and in exchange for the sale of a FERC-jurisdictional product conditioned on clearing in any RPM Auction.”<sup>84</sup> PJM is also clarifying that “conditioned on clearing in any RPM Auction” means “directives as to the price level at which a Generation Capacity Resource must be offered in the RPM Auction or directives that the Generation Capacity Resource is required to clear in any RPM Auction.”<sup>85</sup> Section III.D below details that the Commission will be the arbiter of which state actions constitute Conditioned State Support and that current policies that may otherwise fit the definition of Conditioned State Support are exempt from the definition.

Consistent with the proposed MOPR’s aim of only mitigating offers for resources where an uneconomic offer is the result of an Exercise of Buyer-Side Market power or a state-imposed condition of support, PJM is limiting the universe of resources potentially subject to the MOPR to Generation Capacity Resources, and will not apply the MOPR to

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<sup>82</sup> *Hughes*, 136 S. Ct. at 1299.

<sup>83</sup> *Hughes*, 136 S. Ct. at 1296.

<sup>84</sup> Proposed Tariff, Definitions – C-D (Conditioned State Support).

<sup>85</sup> Proposed Tariff, Definitions – C-D (Conditioned State Support).

Demand Resources and Energy Efficiency Resources. Application of the MOPR to only Generation Capacity Resources is consistent with historic MOPR practices before the Expanded MOPR. Further, PJM is not aware of any evidence that would support extension of buyer-side market protections to these small-scale, generally low-cost, and disparate resources.<sup>86</sup> Accordingly, only Generation Capacity Resources should be subject to the MOPR.

***B. PJM’s Approach Will Rely on Capacity Market Sellers to Certify Whether Their Generation Capacity Resources Meet the Tariff Requirements for Being Subject to the MOPR.***

Taking advantage of the fact that Capacity Market Sellers know best whether their Generation Capacity Resources is entitled to receive Conditioned State Support or whether the Capacity Market Seller plans to use the resource to exercise Buyer-Side Market Power, PJM is proposing that sellers “self-certify” whether their resources should be subject to the MOPR.<sup>87</sup> This approach is similar to the existing certification process under the Expanded MOPR that the Commission previously accepted where Capacity Market Sellers certify whether they expect to receive a State Subsidy in advance of the capacity auction.<sup>88</sup> Like the existing approach, PJM envisions that this certification process would be accomplished electronically, as a “check the box” line item in the capacity auction interface known as Capacity Exchange.

The certification process is an appropriate starting point for review, as it allows the parties who know best (the Capacity Market Sellers) to identify whether the MOPR should

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<sup>86</sup> PJM may revisit whether it makes sense to extend the MOPR to Demand Resources and Energy Efficiency Resources, based on any changes in circumstances or gained experience with the focused MOPR.

<sup>87</sup> See generally proposed Tariff, Attachment DD, section 5.14(h-2)(1).

<sup>88</sup> *PJM Interconnection*, 173 FERC ¶ 61,061, at P 323.

be applied and, as Ms. Morelli explains, avoids imposing an unduly burdensome tasks of requiring PJM and the IMM to potentially review every bilateral contract and all the other relevant facts and circumstances surrounding each Generation Capacity Resource.<sup>89</sup> Moreover, the requirement of a Capacity Market Seller certification itself has a disciplining effect, given that the submittal of a false affidavit could make the Capacity Market Seller subject to action by the Commission's Office of Enforcement.

In addition, the certification process is a reasonable tool for mitigating Buyer-Side Market Power. As Dr. Graf explains, the risk of Buyer-Side Market Power actually occurring is lower relative to the risk of supplier-side market power occurring.<sup>90</sup> This is due to the significant obstacles to successfully accomplishing the Exercise of Buyer-Side Market Power (e.g., the large cost outlay to construct a new resource, and the likely need to suppress prices over multiple years for Buyer-Side Market Power strategy to be economic). Thus, Dr. Graf explains that in "design[ing] . . . market power mitigation mechanisms[, one] necessarily must balance multiple objectives of minimizing false positives (over-mitigation), minimizing false negatives (under-mitigation), and minimizing administrative burden to PJM and market participants."<sup>91</sup> PJM's proposed certification *plus* review process is a just and reasonable approach, as is properly balances over- and under-mitigation.

Capacity Market Sellers will need to provide such certifications no later than 150 days prior to the relevant RPM Auction.<sup>92</sup> However, for the upcoming the Base Residual

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<sup>89</sup> Morelli Aff. ¶¶ 9, 23.

<sup>90</sup> Graf Aff. ¶ 15.

<sup>91</sup> Graf Aff. ¶ 15.

<sup>92</sup> Proposed Tariff, Attachment DD, section 5.14(h-2)(1)(A).

Auction for the 2023/2024 Delivery Year, because the focused MOPR will not be in effect 150 days before that auction is scheduled in December 2021, PJM will post on its website the applicable certification deadline as soon as practicable upon the issuance of a Commission order accepting this proposal.<sup>93</sup> Certifications are generally necessary this far in advance of an auction to allow sufficient time for PJM to make any necessary filings with the Commission, and to allow time for the Commission to issue an order regarding state programs that may be deemed Conditioned State Support.<sup>94</sup> In addition, PJM and the IMM will need time to review for potential Buyer-Side Market Power given the fact-intensive nature of the test described below in section III.C.

To that end, Capacity Market Sellers will need to certify (1) whether, at the time of certification, their “Generation Capacity Resource is receiving or expected to receive Conditioned State Support”<sup>95</sup> and (2) “that 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.”<sup>96</sup> The specific certification language that Capacity Market Sellers are expected to attest to for Conditioned State Support is as follows:

By submitting “Yes”, the Capacity Market Seller certifies that this Generation Capacity Resource is receiving or expected to receive Conditioned State Support under any legislative or other governmental

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<sup>93</sup> Proposed Tariff, Attachment DD, section 5.14(h-2)(1)(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. . . .”).

<sup>94</sup> Morelli Aff. ¶ 26.

<sup>95</sup> Proposed Tariff, Attachment DD, section 5.14(h-2)(1)(A)(i).

<sup>96</sup> Proposed Tariff, Attachment DD, section 5.14(h-2)(1)(A)(ii).

policy or program that is effective at the time of this certification. By submitting “No”, the Capacity Market Seller certifies that Generation Capacity Resource is not receiving or expected to receive Conditioned State Support under any legislative or other governmental policy or program that is effective at the time of this certification.

Separately, the specific certification language that Capacity Market Sellers are expected to attest to for Buyer-Side Market Power is as follows:

By submitting “Yes”, the Capacity Market Seller acknowledges the prohibition of the Exercise of Buyer-Side Market Power and does not intend to Exercise Buyer-Side Market Power for this Generation Capacity Resource. By submitting no, the Capacity Market Seller does not certify to the above statement.

Also similar to the existing process, the certification requirement for Conditioned State Support, once made, does not need to be repeated for each auction, unless there is a change in the expectation of receiving Conditioned State Support.<sup>97</sup> In contrast, Capacity Market Sellers are required to certify, in advance of each RPM Auction, that they do not intend to exercise Buyer-Side Market Power. This distinction is appropriate because unlike Conditioned State Support, Sell Offers that are being submitted for each auction may differ based on each Capacity Market Seller’s offer strategy. Moreover, given the importance and reliance on the Capacity Market Sellers’ certification, it is reasonable that all Capacity Market Sellers certify in advance of each auction whether it intends to exercise Buyer-Side Market Power.

As Ms. Morelli testifies, PJM proposes that Capacity Market Sellers’ self-certifications will be made in good faith, and the intention is to grant a presumption of innocence to Capacity Market Sellers if they make these certifications.<sup>98</sup> Thus, like the

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<sup>97</sup> Proposed Tariff, Attachment DD, section 5.14(h-2)(1)(C).

<sup>98</sup> Morelli Aff ¶ 25.

existing process, Capacity Market Sellers are responsible for their own certifications, “irrespective of any guidance developed by” PJM or the IMM.<sup>99</sup> This approach is reasonable, as it would be overly burdensome and unworkable for PJM to: (1) annually study each and every state or local government policy or program and evaluate whether they would convey a benefit conditioned on a bid to clear requirement and (2) annually review each and every contract a seller may have to determine whether an ostensibly merchant generator has an incentive to exercise Buyer-Side Market Power.<sup>100</sup>

Moreover, requiring all sellers to annually submit data to PJM that would allow PJM to perform such extensive reviews also would be overly burdensome on the seller. As such, in lieu of requiring sellers to provide supporting information along with the certification, PJM will presume that the seller accurately certified whether their resource should be subject to the MOPR. Finally, all Capacity Market Sellers have “an ongoing obligation” to update their certifications in the event of a “material change in status” within 30 days of such change.<sup>101</sup>

Notwithstanding the foregoing, PJM will not simply take the self-certifications purely at face value as the proposed Tariff language includes the ability for PJM and the IMM to initiate a further inquiry, where appropriate. If PJM or the Market Monitor has a reasonable basis to initiate an inquiry that a Capacity Market Seller may commit an Exercise of Buyer-Side Market Power with respect to a certain resource, PJM or the Market

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<sup>99</sup> Proposed Tariff, Attachment DD, section 5.14(h-2)(1)(B).

<sup>100</sup> See *Morelli Aff.*, ¶¶ 9, 23. In addition, placing the burden on PJM would require PJM to examine the load position of every Capacity Market Seller to look across its corporate family to determine the seller’s net load position, and therefore whether they potentially would have the incentive to exercise Buyer-Side Market Power.

<sup>101</sup> Proposed Tariff, Attachment DD, section 5.14(h-2)(1)(C).

Monitor may initiate a fact-specific review. PJM or the Market Monitor may conduct all parts of the inquiry, while PJM, with the advice and input of the Market Monitor, will ultimately determine whether to apply the MOPR, based on the outcome of such inquiry. Similarly, if a seller certifies that the resource will not receive any Conditioned State Support, but PJM and/or the IMM is aware of Conditioned State Support that the resource may receive, PJM and/or the IMM may inquire with the Capacity Market Seller. The outcome of such inquiries may result in the resource being subject to the MOPR.<sup>102</sup>

Given the importance of timely self-certifications, the failure to timely submit any certification for a Generation Capacity Resource by 150 days before an RPM Auction results in that resource being subject to the MOPR.<sup>103</sup> In the absence of a seller certification that the resource should not be subject to the MOPR, it is reasonable and appropriate to presume that the resource should be subject to the MOPR. As explained, it is incumbent on the Capacity Market Seller to attest that it does not intend to use the resource in an Exercise of Buyer-Side Market Power or receiving Conditioned State Support; PJM simply cannot confidently make those judgments without an annual fact investigation. Thus, PJM needs the certifications by 150 days before the auction to allow sufficient time for any necessary fact-specific investigation or to allow for the initiation and completion of proceedings before the Commission in advance of the RPM Auction.<sup>104</sup> If a seller fails to submit a timely certification, it may still seek a unit-specific exception to the applicable

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<sup>102</sup> Depending on the outcome of an investigation, PJM may request a seller to change their certification and/or apply MOPR if PJM determines that the subject resource will receive Conditioned State Support and the Commission has accepted that the state program provides Conditioned State Support.

<sup>103</sup> Proposed Tariff, Attachment DD, section 5.14(h-2)(2)(C).

<sup>104</sup> As noted, for the 2023/2024 Base Residual Auction, PJM proposes to shorten this certification deadline and post the actual deadline on the PJM website that will be approximately two weeks from the issuance of a FERC order accepting this filing.

default MOPR Floor Offer Price; such request must be submitted no later than 120 days before the RPM Auction.<sup>105</sup>

**C. *The Focused MOPR Will Protect Against Exercises of Buyer-Side Market Power.***

As Dr. Walter Graf, PJM’s Senior Director of Economics explains, the exercise of buyer-side market power occurs when a Capacity Market Seller has the economic incentive and ability to suppress market prices, and “requires *uneconomic behavior* to lower market offers below the competitive level to suppress prices,”<sup>106</sup> Thus, to protect against the Exercise of Buyer-Side Market Power, the focused MOPR is designed to prevent Capacity Market Sellers from submitting an uneconomically low Sell Offer for a given Generation Capacity Resource so as to depress the RPM Auction clearing price for the overall benefit of the seller’s Load Interest, an affiliate’s Load Interest, or the Load Interest of an entity in contractual privity with the seller. PJM proposes to define Buyer-Side Market Power as “the ability of Capacity Market Sellers with a Load Interest to suppress RPM Auction clearing prices for the overall benefit of their (and/or affiliates) portfolio of generation and load.”<sup>107</sup> To the extent PJM determines that a Generation Capacity Resource may be used in an Exercise of Buyer-Side Market Power, the Sell Offer for such resource would be mitigated through the MOPR.<sup>108</sup> Also, to the extent a Capacity Market Seller certifies that it intends to use a resource in an Exercise of Buyer-Side Market Power, that resource shall be subject to the MOPR.<sup>109</sup>

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<sup>105</sup> Proposed Tariff, Attachment DD, section 5.14(h-2)(2)(C).

<sup>106</sup> Graf Aff. ¶ 9.

<sup>107</sup> Proposed Tariff, Definitions – A-B (Buyer-Side Market Power).

<sup>108</sup> Proposed Tariff, Attachment DD, section 5.14(h-2)(2)(B)(iii)

<sup>109</sup> Proposed Tariff, Attachment DD, section 5.14(h-2)(2)(B)(i)



If PJM or the IMM has a reasonable basis to initiate an inquiry into whether a Capacity Market Seller may commit an Exercise of Buyer-Side Market Power with respect to a certain resource, PJM or the IMM may initiate a fact-specific review. PJM or the IMM may conduct all parts of the inquiry, while PJM, with the advice and input of the IMM, will ultimately determine whether to apply the MOPR, based on the outcome of such inquiry. While PJM does not propose to establish a bright-line test for when it may initiate an inquiry of Buyer-Side Market Power, Dr. Graf explains that “[a]n inquiry may be initiated if a Capacity Market Seller intends to offer a resource or technology believed to be uneconomic, in a location where the [Capacity] [M]arket [S]eller and/or its affiliates have a net short position (that is, more load than generation in a given Locational Deliverability Area (“LDA”)).”<sup>110</sup>

Prior to initiating an inquiry, the PJM and/or the IMM must provide the seller a written notification, at least 135 days prior to the conduct of the Base Residual Auction, stating the bases for PJM’s and/or the IMM’s inquiry and such notification will initiate the fact-specific review.<sup>111</sup> Providing such written notification at least 135 days prior to the auction will provide Capacity Market Sellers with sufficient time to proactively seek a unit-specific exception to the default MOPR floor price in case PJM determines during the fact-specific review that the resource fails the Buyer-Side Market Power test.<sup>112</sup>

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<sup>110</sup> Graf Aff. ¶ 20.

<sup>111</sup> Proposed Tariff, Attachment DD, section 5.14(h-2)(2)(B)(i). For the upcoming 2023/2024 Base Residual Auction, the applicable dates will be posted on PJM’s website. *Id.*

<sup>112</sup> As noted, PJM proposes shorter deadlines for the 2023/2024 Base Residual Auction given that the auction is schedule to commence in December 2021. This is reasonable given that this filing proposes a focused MOPR, any Generation Capacity Resource that is subject to the new MOPR likely would have been subject to the Expanded MOPR. As a result, Capacity Market Sellers will likely have already submitted unit-specific reviews under the Expanded MOPR provisions by the current August 3, 2021 deadline and would have the option to utilize the unit-specific floor price should any Buyer-Side Market Power determinations be made for the 2023/2024 Delivery Year. Notwithstanding, while it is still possible, although unlikely, that an

Key to PJM's MOPR approach is that initiation of a fact-specific review does not mean that the MOPR is triggered automatically. Rather, PJM and/or the IMM would review whether the seller has the ability and incentive to exercise Buyer-Side Market Power through a Sell Offer for the subject Generation Capacity Resource.<sup>113</sup> During the fact-specific review, PJM and/or the IMM will investigate whether the seller has the ability and the incentive to exercise Buyer-Side Market Power, and the 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."<sup>114</sup> For example, a seller may be able to demonstrate that it is a purely merchant generation resource seller and has no direct relationship with any Load Interest.

As discussed below, PJM will test for whether the Generation Capacity Resource provides the seller the ability to exercise Buyer-Side Market Power, and whether the combination of such ability and the associated Load Interests provides the Capacity Market Seller with the incentive to exercise Buyer-Side Market Power. Based on those tests and the fact-specific review, PJM, with the advice and input of the IMM will "determine whether a Generation Capacity Resource may be the subject of a Sell Offer that would be an Exercise of Buyer-Side Market Power."<sup>115</sup> In short, for a resource to be subject to the MOPR due to Buyer-Side Market Power concerns, the Capacity Market Seller must have

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existing resource may not be subject to the Expanded MOPR, but could be subject to the new MOPR, the default MOPR floor price for such existing resource is likely to be so low that use of the default, rather than a unit-specific floor price, would not present a barrier to clearing.

<sup>113</sup> Proposed Tariff, Attachment DD, section 5.14(h-2)(2)(B)(i).

<sup>114</sup> Proposed Tariff, Attachment DD, section 5.14(h-2)(2)(B)(i).

<sup>115</sup> Proposed Tariff, Attachment DD, section 5.14(h-2)(2)(B)(iii).

a Load Interest (as PJM proposes to define that term) and, then, must have both the ability and incentive to exercise Buyer-Side Market Power.<sup>116</sup>

If PJM makes such determination or the seller certifies that it intends to use the resource to exercise Buyer-Side Market Power, the resource will be subject to the MOPR. If a resource is subject to the MOPR for Buyer-Side Market Power concerns, PJM will provide the seller a notice, with a written explanation.<sup>117</sup> Of course, any seller that disagrees with PJM’s determination that a generation resource is subject to the MOPR “may seek any remedies available to it from [the Commission],” though PJM “will proceed with administration of the Tariff and market rules based on its determination hereunder unless [the Commission] by order directs otherwise.”<sup>118</sup>

1. *PJM and/or the IMM Will Test for Whether the Generation Capacity Resource Provides the Seller the Ability to Exercise Buyer-Side Market Power.*

To exercise Buyer-Side Market Power, the Capacity Market Seller must have the *ability* to exercise Buyer-Side Market Power. In other words, the Generation Capacity Resource must be of sufficient size that an uneconomic Sell Offer (i.e., a Sell Offer below the resource’s costs) would reduce the clearing price for the area in which the resource is located (e.g., LDA or the Rest of RTO region).<sup>119</sup> For example, consider a new Generation Capacity Resource that has 800 MW of Unforced Capacity (“UCAP”) and will be constructed in a small constrained LDA, like BGE—where 2,866.2 MW were offered in the last Based Residual Auction (“BRA”) (for the 2022/2023 Delivery Year) and 2,494.5

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<sup>116</sup> Proposed Tariff, Attachment DD, section 5.14(h-2)(2)(B)(iii).

<sup>117</sup> Proposed Tariff, Attachment DD, section 5.14(h-2)(2)(B)(iii).

<sup>118</sup> Proposed Tariff, Attachment DD, section 5.14(h-2)(2)(B)(iii).

<sup>119</sup> Graf Aff. ¶ 22.

MW cleared.<sup>120</sup> An uneconomic Sell Offer for such Generation Capacity Resource likely would have the ability to materially reduce the clearing price by displacing nearly 800 MWs of UCAP that had cleared in the previous BRA, reducing the clearing price from \$126.50/MW-day to \$87.98/MW-day. By contrast, assume a 20 MW resource located in central Pennsylvania (the “Rest of RTO” region), where 144,477.3 MW cleared the last BRA. An uneconomic Sell Offer for such Generation Capacity Resource would *not* be able to materially affect the clearing price. The price impact of such a suppressed resource offer would have been precisely \$0/MW-day in the last auction.<sup>121</sup>

PJM’s proposed MOPR will screen out those resources with which sellers do *not* have the ability to exercise Buyer-Sider Market Power. Dr. Graf explains that, to determine whether a given resource would provide a seller the ability to exercise Buyer-Side Market Power, “PJM [or the IMM] will perform a test 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,” based on the “expected supply and demand conditions in the relevant LDAs and regional transmission organizations (“RTO”).”<sup>122</sup> Dr. Graf explains that this test will consider (1) “expected supply and demand conditions in the region of the market clearing prices and quantities in recent RPM Auctions,” (2) “whether the relevant LDAs have been constrained in recent RPM Auctions,” and (3) “reasonably expected material changes in an LDA including the modeling of the LDA (i.e., assumptions about capacity import capabilities into an LDA

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<sup>120</sup> Graf Aff ¶ 22.

<sup>121</sup> Graf Aff. ¶ 22.

<sup>122</sup> Graf Aff. ¶ 22.

and expected changes in supply and demand for the applicable Delivery Year.”<sup>123</sup> PJM has detailed this test in the proposed focused MOPR, and if the test shows that the resource would provide the seller the ability to affect RPM Auction clearing prices, then the seller “shall be deemed to have the ability to exercise Buyer-Side Market Power.”<sup>124</sup>

2. *PJM and/or the IMM Will Test for Whether the Generation Capacity Resource Provides the Seller the Incentive to Exercise Buyer-Side Market Power.*

An essential element of any Exercise of Buyer-Side Market Power is that the seller must have the *incentive* to depress clearing prices. That means it must have a Load Interest that will benefit from the lower capacity market prices. That is, for “buyer”-side market power, the seller must somehow act on behalf of a buyer, which in the capacity market context is load. Otherwise, there is no incentive for the seller to seek to depress the clearing price. Therefore, as an initial threshold matter, sellers that do not have any load, are not affiliated with a LSE, or are not in contractual privity with a LSE with respect to the subject Generation Capacity Resource, will not be suspected of exercising Buyer-Side Market Power, and such Generation Capacity Resource will not be subject to the MOPR.

Not all sellers with a Load Interest inherently will have an incentive to depress auction clearing prices, however. Sellers that hold a significant portfolio of generation capacity and a small Load Interest would *not* have the economic incentive to depress prices. Rather, on an overall basis, the economic incentive is to seek as much money as possible through the market. Accordingly, PJM’s proposed MOPR will screen out resources for which the seller does *not* have an incentive to exercise Buyer-Side Market Power.

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<sup>123</sup> Graf Aff. ¶ 22

<sup>124</sup> See Proposed Tariff, Attachment DD, section 5.14(h-2)(2)(B)(i).

To determine whether a seller has the incentive to exercise Buyer-Side Market Power, PJM and/or the IMM will test whether the seller could receive a net benefit to their portfolio of generation and load due to the submission of an offer that is below the resource's avoidable going forward costs.<sup>125</sup> Dr. Graf explains that test will allow PJM to “determine whether, given the ability to suppress prices identified in the relevant LDAs and RTO, such price suppression would be economically beneficial to the participant. PJM would compare” its expected cost with its economic benefit.<sup>126</sup>

In order to perform this test, PJM will need to obtain data from the seller related to the resource's costs and revenues. Dr. Graf explains that such data would be “similar to that provided in the process for determining a unit-specific MOPR Floor Offer Price.”<sup>127</sup> PJM will compare the expected cost of the resource, which will “reflect the implied subsidy on the resource in question, where the implied subsidy is the expected excess economic cost of the resource above expected market revenues” against the expected benefit to the seller, which will “reflect the . . . expected net short position . . . in the relevant LDAs and RTO multiplied by the price change resulting from offering the resource uneconomically.”<sup>128</sup> The seller's net short position will be determined “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.”<sup>129</sup> Using three

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<sup>125</sup> See Proposed Tariff, Attachment DD, section 5.14(h-2)(2)(B)(ii).

<sup>126</sup> Graf Aff. ¶ 23.

<sup>127</sup> Graf Aff. ¶ 23.

<sup>128</sup> Graf Aff. ¶ 23.

<sup>129</sup> Proposed Tariff, Attachment DD, section 5.14(h-2)(2)(B)(ii).

years of data appropriately smooths volatility and provides a reasonable view of the applicable load and generation portfolio.<sup>130</sup> Finally, this analysis will consider whether the seller's "capacity costs based on RPM Auction clearing prices are directly passed through to load," which would make the seller unable to profit from a suppressed clearing price, and consider whether the seller has any capacity under contract at a price that simply passes through the RPM Auction clearing price, which would affect the seller's incentive to exercise Buyer-Side Market Power.

Dr. Graf explains that as part of the incentive test, PJM will test the resource at a variety of price levels to determine whether there is a level where the offer is both uneconomic and provides a net benefit to the seller's portfolio of generation and Load Interests given the savings that result from reduced charges to load.<sup>131</sup> "The starting point for determining the economically justifiable offer level would be the default MOPR Floor Offer Price, or unit-specific MOPR Floor Offer Price, if elected by the seller," because these values reflect the resource's "avoidable going forward costs net of expected revenues."<sup>132</sup>

To the extent the test demonstrates an offer level below the MOPR Floor Offer Price at which the seller's "expected benefit outweighs the expected cost," then the seller "shall be deemed to have the incentive to exercise Buyer Side Market Power."<sup>133</sup> However, just because a given offer level may provide the seller with an overall benefit does not

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<sup>130</sup> In addition, this net short approach is the same one adopted for the MOPR in Docket No. ER13-535. *PJM Interconnection, L.L.C.*, Submittal of PJM Interconnection, L.L.C., Docket No. ER13-535-000, at 21 (Dec. 7, 2012); proposed Tariff, Attachment DD, section 5.14(h)(6)(iii).

<sup>131</sup> Graf Aff. ¶ 24.

<sup>132</sup> Graf Aff. ¶ 24.

<sup>133</sup> Proposed Tariff, Attachment DD, section 5.14(h-2)(2)(B)(i)(b).

mean that an offer at that price level would be improper or inappropriate. Accordingly, PJM proposes to provide in the Tariff that “[i]f 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.”<sup>134</sup> Further, to reduce ambiguity, PJM proposes to include in the Tariff that “[o]ut-of-market compensation (such as from renewable energy credits and zero emission credits)” is permissible and “may be used to support the economics of the resource under review” but only to the extent that such compensation is “not tied to either Conditioned State Support or a bilateral contract that directs the submission of an offer to lower market clearing prices.”<sup>135</sup>

To assist in determining of Buyer-Side Market Power, PJM proposes to detail in the Tariff the following non-exhaustive list of circumstances that would not support an inquiry into or a determination that a resource may be used in an Exercise of Buyer-Side Market Power:

- (a) the Generation Capacity Resource is a merchant generation supply resource 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 accepted by the RERRA, provided that any such plan approval or contracts do not direct the submission of an uneconomic

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<sup>134</sup> Proposed Tariff, Attachment DD, section 5.14(h-2)(2)(B)(i)(b).

<sup>135</sup> Proposed Tariff, Attachment DD, section 5.14(h-2)(2)(B)(i)(b).



offer to deliberately lower market clearing prices or for the Capacity Market Seller to otherwise perform an Exercise of Buyer-Side Market Power.<sup>136</sup>

Dr. Graf explains why each of these listed circumstances, by themselves, do not raise concerns of Buyer-Side Market Power.<sup>137</sup> Of note, Generation Capacity Resources owned by, or bilaterally contracted to Self-Supply Sellers, are generally exempt since they construct and/or enter into long-term contracts for resources to maintain a relative balance between supply and demand.

PJM proposes to define Self-Supply Sellers as: (1) vertically integrated utilities that include their generation assets “in its regulated rates, and earns a regulated return on its investment in such generation; and (2) public power entities, i.e., “electric cooperatives that are either rate regulated by the state or have their long-term resource plan approved or otherwise reviewed and accepted by a Relevant Electric Retail Regulatory Authority and municipal utilities or joint action agencies that are subject to regulation by a Relevant Electric Retail Regulatory Authority.”<sup>138</sup> As defined, each Self-Supply Seller is rate regulated or has regulatory oversight of its long-range resource planning. Such oversight is relevant because “[s]elf-supply entities construct and/or enter into long-term contracts for resources to maintain a relative balance between supply and demand. These entities and their customers benefit from relatively stable costs primarily reflecting their cost to maintain such a portfolio, rather than volatile costs reflecting large capacity purchases at uncertain prices from the PJM capacity market.”<sup>139</sup> As a result, “[i]t is entirely economic

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<sup>136</sup> Proposed Tariff, Attachment DD, section 5.14(h-2)(2)(B)(ii).

<sup>137</sup> Graf Aff ¶ 25.

<sup>138</sup> Proposed Tariff, Definitions – R-S (Self-Supply Seller).

<sup>139</sup> Graf Aff. ¶ 25.

for such an entity to make long-term plans, and to offer resources consistent with these plans into the capacity market.”<sup>140</sup>

In addition to the circumstances that would not support a determination of Buyer-Side Market Power described above, a Generation Capacity Resource receiving compensation in support of characteristics aligned with well-demonstrated customer preferences would not, in and of itself, be a basis for the determination of Buyer-Side Market Power.<sup>141</sup> Offers that reflect customers’ preference for the resource (or its particular attributes) would not constitute Exercise of Buyer-Side Market Power because they do not uneconomically lower capacity market offers and instead simply reflect an offer that considers a privately ascribed value.<sup>142</sup>

***D. The Focused MOPR Will Protect Against Conditioned State Support, i.e., State Bidding Requirements that Would Improperly Affect Clearing Prices.***

To protect against state actions improperly interfering with clearing prices in the capacity market, the proposed MOPR would mitigate Sell Offers for Generation Capacity Resources that will receive material benefits from a state policy in exchange for the sale of a FPA-jurisdictional product *and* such support is conditioned on either the resource clearing an RPM Auction or the seller offering the resource at a specific price level, i.e., Conditioned State Support. Such “bid to clear” requirements in effect makes the seller indifferent as to resource’s economics when submitting offer in the capacity market, and lets the state set the price of the FERC-jurisdictional product.

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<sup>140</sup> Graf Aff. ¶ 25.

<sup>141</sup> *Id.*

<sup>142</sup> Graf Aff. ¶ 26.

The “bid to clear” standard for applying the MOPR is appropriate, as such requirements improperly intrude on price formation in the capacity market.<sup>143</sup> PJM is aware of the critique that this standard is the same one applied by the courts for determining whether a state policy is pre-empted by the FPA, and therefore, such a MOPR standard is unnecessary and review of such bid to clear requirements is best left to the courts. However, such a standard for applying the MOPR *is necessary*. Court review can take a long time, and may not be able to protect the market in a timely manner. Moreover, in a judicial proceeding, the court’s principle remedy is to void all or the offending portion of the relevant statute or regulatory order. Such may have the unintended effect of harming non-utility entities who may also benefit from that particular state law or program. In contrast, PJM’s proposed MOPR allows the statute to remain in effect and applies a more surgical solution, which will safeguard the market from such state policies by mitigating Sell Offers to the competitive cost-based level. In so doing, PJM is not assuming the role of the courts and is not declaring a state policy or program unlawful.

Further, PJM proposes that the Commission should be the arbiter, and only upon a Commission determination will a resource receiving such state support be subject to the MOPR. While PJM does not propose to determine which state policies or programs impermissibly veer into conditioning benefits on bid to clear auction behavior, PJM will identify for the Commission those policies and programs its suspects may provide Conditioned State Support.

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<sup>143</sup> Morelli Aff. ¶ 14.

To effectuate this, the proposed Tariff provides that PJM would submit an FPA section 205 filing with the Commission proposing that such policy or program be classified as Conditioned State Support.<sup>144</sup> PJM would timely submit such a section 205 filing before the applicable RPM Auction so as to allow the Commission sufficient time to act, and parties will know before the auction whether the identified state policy constitutes Conditioned State Support. Interested parties, including the seller of any resource receiving such support, would be afforded the opportunity to make their case to the Commission as to whether such policy constitutes Conditioned State Support. As part of this proposal, PJM is proposing a new Tariff, Attachment DD-3 to contain a list of policies the Commission has accepted as Conditioned State Support. In the section 205 filing, PJM would propose to update proposed Tariff, Attachment DD-3, to add a specific state policy or program as Conditioned State Support.<sup>145</sup>

Commission approval (whether by order or operation of law) that a specific policy or program constitutes Conditioned State Support would result in subjecting to the MOPR any resource receiving support through such policy/program.<sup>146</sup> Thus, any resource for which a seller certifies that it is receiving Conditioned State Support or PJM, with the advice and input of the IMM, identifies as being “reasonably expected to receive such Conditioned State Support” “will be subject to the provisions of the Minimum Offer Price Rule.”<sup>147</sup>

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<sup>144</sup> Proposed Tariff, Attachment DD, 5.14(h-2)(2)(A)(i).

<sup>145</sup> Proposed Tariff, Attachment DD-3.

<sup>146</sup> Proposed Tariff, Attachment DD, section 5.14(h-2)(2)(A)(ii).

<sup>147</sup> Proposed Tariff, Attachment DD, section 5.14(h-2)(2)(A)(ii).

PJM's proposal is reasonable, as the question of whether a state policy improperly intrudes on price formation in the capacity market is ultimately one involving the interaction of state and federal authority,<sup>148</sup> and the Commission is better suited than PJM to make that final determination after receiving PJM and the IMM's recommendations, as well as those of interested stakeholders. Moreover, since the state action might impact more than one market participant, this approach ensures states and sellers can present their arguments to the Commission in the first instance, and will not need to resort to submitting complaints against PJM before or during the auction. As such, this approach creates certainty in auction outcomes, provides a clear due process vehicle for all affected parties, including the states, and minimizes the likelihood of auction results being questioned through a misapplication of the MOPR.<sup>149</sup>

Clearly, not every state policy that provides benefits to resources would qualify as Conditioned State Support. Ms. Morelli testifies that policies or programs that "do not explicitly pay for a FERC-jurisdictional product, or, do not condition payment on clearing in the capacity market or direct the level at which such resources must be offered into the market," do not qualify as Conditioned State Support and therefore such policies would not result in application of the MOPR. Specifically, Ms. Morelli identifies the following policies/programs would not constitute Conditioned State Support as they exist today and would, therefore, not require resources receiving support through them to be subject to MOPR:

- Non-FERC jurisdictional programs such as RECs/ZECs/RGGI;
- State and local tax incentives;

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<sup>148</sup> Morelli Aff. ¶¶ 15-16.

<sup>149</sup> Morelli Aff. ¶ 16.

- State retail default service auctions;
- Incentives related to fuel supplies; and
- Federal regulatory programs administered by states such as PURPA and the Cross-State Air Pollution Rule.<sup>150</sup>

PJM is proposing to codify that such policies and programs, as they exist today, do not constitute Conditioned State Support, and provides in the proposed MOPR Tariff a non-exhaustive list of “Government policies or programs that do not provide payments or other financial benefit outside of PJM markets and in exchange for the sale of a FERC-jurisdictional product conditioned on clearing in any RPM Auction do not constitute Conditioned State Support,” including policies like those listed above.<sup>151</sup>

In addition, PJM proposes that Conditioned State Support “shall not be determined solely based on the business model of the Capacity Market Seller”<sup>152</sup> and PJM specifically identifies the business models of each Self-Supply Entity as not constituting Conditioned State Support. The long-standing business models of these public power entities does not qualify as Conditioned State Support for the simple reason that such support is not conditioned on specific bidding behavior.

Finally, PJM proposes to categorically exclude from the definition of Conditioned State Support any policy or program that is currently on the books or is effective. Such “Legacy Policies” will not result in resources being subject to the MOPR.<sup>153</sup> Exempting

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<sup>150</sup> Morelli Aff. ¶ 17.

<sup>151</sup> Proposed Tariff, Attachment DD, section 5.14(h-2)(2)(A)(i); *see also id.* (“Examples of such government policies 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).”).

<sup>152</sup> Proposed Tariff, Attachment DD, section 5.14(h-2)(2)(A)(i);

<sup>153</sup> PJM is proposing to define “Legacy Policy” as “any legislative, executive, or regulatory action that

existing policies and programs (like the Maryland Offshore Wind Energy Act) and applying prospectively this new MOPR is reasonable, as it is least disruptive to the states and efficiently allows states to craft future policies and programs to avoid improperly interfering with the capacity market.

Accordingly, the focused MOPR will accommodate State policies encouraging the development of preferred resource types and also accommodate long-standing public power and vertically integrated utility business models. By mitigating the Sell Offer for resources expected to receive Conditioned State Support, PJM is not precluding such resources from clearing an auction and receiving a capacity commitment. Rather, PJM is merely seeking to prevent the state action from directly interfering with the price of capacity. Such a resource will still clear to the extent it is still economic without the revenues from the Conditioned State Support.

***E. PJM Does Not Propose to Change How the MOPR Functions or the Determination of Default and Unit-Specific MOPR Floor Offer Prices.***

While PJM proposes to narrow which resources may be subject to the MOPR, PJM generally does not propose to alter how the MOPR actually functions. That is, whether a resource is subject to the State Subsidy MOPR in section 5.14(h-1) or the new, more focused MOPR in section 5.14(h-2), the determination of the applicable default or unit-specific MOPR Floor Offer Price will generally be the same. To illustrate the few differences in determining the applicable MOPR Floor Offer Price between the new, focused MOPR and the State Subsidy MOPR, PJM includes as Attachment G to this letter

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specifically directs a payment outside of PJM Markets to a designated or prospective Generation Capacity Resource and the enactment of such action predates September 1, 2021, regardless of when any implementing governmental action is enacted or promulgated to specifically effectuate the action to direct payment outside of PJM Markets.” Proposed Tariff, Definitions – L-M-N.

a redline comparison showing the targeted revisions to the default and unit-specific floor price determinations.

*1. PJM Is Not Proposing to Change the Framework for Determining MOPR Floor Offer Prices*

Significantly, PJM proposes *no change* to setting MOPR Floor Offer Prices on either net cost of new entry (“CONE”) or net Avoidable Cost Rate (“ACR”) values depending on whether a resource is new (i.e., never cleared an RPM Auction) or existing (i.e., has cleared an RPM Auction at any price level). In other words, through this proposal PJM proposes to change the resources that are the focus of the MOPR, and not the determination of the applicable MOPR Floor Offer Prices. Thus, although there has been some discussion about replacing the current approved use of net CONE for new resources, that is not within the scope of PJM’s proposal. The Commission must evaluate PJM’s proposal here within the bounds of section 205<sup>154</sup> and the scope of PJM’s proposal in this filing,<sup>155</sup> and may not approve material deviations.<sup>156</sup>

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<sup>154</sup> See *Emera Maine v. FERC*, 854 F.3d 9, 24 (D.C. Cir. 2017) (“[S]ection 205 is intended for the benefit of the utility . . . and FERC plays an essentially passive and reactive role under section 205.” (internal quotations and citations omitted)).

<sup>155</sup> See, e.g., *PJM Interconnection, L.L.C.*, 173 FERC ¶ 61,090, at P 18 n.44 (2020) (rejecting challenge to unchanged aspect of PJM’s Tariff, holding that “[t]his filing did not change PJM’s project evaluation of cost containment proposals pursuant to section 1.5.8(c)(2) of the Operating Agreement except to increase the specificity by making cost commitments binding and requiring developers to submit sufficient information. Any consideration of specificity therefore is beyond the scope of a section 205 inquiry into the proposed change” (citing *ANR Pipeline Co. v. FERC*, 771 F.2d 507, 514 (D.C. Cir. 1985) (holding that “when the Commission imposes a change not proposed by the natural gas company -- including an *alteration in an unchanged part of a proposed higher rate*”, the Commission must act pursuant to section 5 of the Natural Gas Act, 15 U.S.C. § 717c, the equivalent of section 206 of the FPA (citing *Pub. Serv. Comm’n of N.Y. v. FERC*, 642 F.2d 1335 (D.C. Cir. 1980)))).

<sup>156</sup> See *NRG Power Mktg., LLC v. FERC*, 862 F.3d 108, 115 (D.C. Cir. 2017) (“Section 205 does not allow FERC to suggest modifications that result in an ‘entirely different rate design’ than the utility’s original proposal or the utility’s prior rate scheme.” (quoting *Western Res. v. FERC*, 9 F.3d 1568, 1578 (D.C. Cir. 1993))).



In any event, as Dr. Graf explains, it is appropriate to consider different costs when establishing MOPR Floor Offer Prices for new or existing resources.<sup>157</sup> While competitive offer levels for both sets of resources should be based on their net avoidable going forward costs (that is, the costs that would be avoided by not providing capacity for that Delivery Year, net of expected revenues), the avoidable costs to be considered differ, reflecting the economic costs for a new versus existing resource.

For a new resource, i.e., one that has never cleared an RPM Auction for any Delivery Year, the competitive offer should reflect *all* of the cost of constructing the resource—the cost of new entry, or CONE.<sup>158</sup> This is reasonable, as such resources are entering the capacity market and thus the costs that would be avoided by not providing capacity for that Delivery Year are *all* the resource’s costs; the resource does not need to be constructed.<sup>159</sup> Dr. Graf explains that a new resource’s net CONE should include “[a]ny costs already expended (sunk) by a new entrant [. . .], as this reflects the competitive, economic offer level of a resource by a competitive participant whose entry decision is

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<sup>157</sup> Graf Aff. ¶¶ 28-32.

<sup>158</sup> Similarly, any uprate of a Generation Capacity Resource that is subject to the MOPR and where such uprate is “participating in the generation interconnection process under Tariff, Part IV, Subpart A,” the uprate is also subject to the MOPR as a new resource and its MOPR Floor Offer Price will be determined based on the applicable net cost of new entry. *See* proposed Tariff, Attachment DD, section 5.14(h-2)(3)(A).

<sup>159</sup> *See PJM Interconnection, L.L.C.*, 161 FERC ¶ 61,252, at P 50 (2017) (“When bidding in PJM’s current market, a competitive resource submits offers that reflect its incremental cost. Before a resource is built, its incremental cost would reflect the unit-specific net CONE, but once the resource has cleared in one auction, its developer would need to begin construction to meet its obligation three years later in the delivery year. At that point, the construction costs incurred prior to subsequent auctions become sunk costs, and they are not part of the resource’s incremental costs going-forward.” (citation omitted)); *PJM Interconnection, L.L.C.*, 135 FERC ¶ 61,022, at P 176 (2011) (“We agree with the IMM that the appropriate duration is that the MOPR offer floor should apply to each new resource in the base residual and each incremental auction until the resource demonstrates that its capacity is needed by the market at a price near its full entry cost -- by clearing one of the PJM capacity auctions (base residual or incremental) at an offer price near its full cost of entry.”); *see also Jackson Generation LLC v. PJM Interconnection, L.L.C.*, 175 FERC ¶ 61,116, at PP 31-35 (2021).

informed by market outcomes (that is, whether the resource clears the capacity market or not).”<sup>160</sup>

In contrast, for an “existing” resource, i.e., one that has cleared an RPM Auction, the competitive offer would reflect only those costs it would avoid by not providing capacity for that Delivery Year. The Tariff already details in Attachment DD, section 6.8 and defines as the “Avoidable Cost Rate” those costs which would be avoided if an existing resource does not provide capacity for a given Delivery Year. Because the market has already shown a need for such a resource, sunk costs are properly excluded.<sup>161</sup>

Using only the Avoidable Cost Rate cost components for a new resource, and ignoring development and construction costs would not be reasonable. First, as the Commission has found, for a resource that is not yet constructed, all of its going forward costs are avoidable.<sup>162</sup> Second, Dr. Graf testifies that “[a]pplying the MOPR at Net ACR for a new resource would not reflect the competitive offer of a resource that no competitive market participant would choose to construct.” He explains that, “[f]or example, a competitive Capacity Market Seller whose prospective resource has high costs would not plan to enter the market, where going forward revenues are insufficient to cover all costs plus a return on investment.”<sup>163</sup> By mitigating to Net CONE in the case of new resources,

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<sup>160</sup> Graf Aff. ¶ 31; *see also Jackson Generation*, 175 FERC ¶ 61,116, at P 33 (“Jackson's decision to construct its resource prior to clearing the auction is not a competitive advantage ‘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’ as required by the Tariff.” (quoting Tariff, Att. DD, section 5.14(h)(5)(iii))).

<sup>161</sup> Graf Aff. ¶ 30.

<sup>162</sup> *See PJM Interconnection*, 171 FERC ¶ 61,035, at PP 157-158; December 2019 Order at PP 139-140.

<sup>163</sup> Graf Aff. ¶ 32.

PJM properly restores the market outcomes to those that would prevail in the absence of the Exercise of Buyer-Side Market Power and Conditioned State Support.

2. *PJM Is Proposing a Handful of Discrete Updates to the Determination of Unit-Specific MOPR Floor Offer Prices.*

In addition to retaining the current State Subsidy MOPR rules for determining the default MOPR Floor Offer Prices, PJM is proposing to generally retain the unit-specific exception process but with a handful small substantive changes. First, PJM proposes to change the name from the “resource-specific” exception back to the “unit-specific” exception. Unit-specific has long been the name of this process, and PJM only changed it for the State Subsidy MOPR to reflect application to Demand Resources and Energy Efficiency Resources, which are not composed of “units” like Generation Capacity Resources.

Second, PJM proposes that in determining a resource’s unit-specific MOPR Floor Offer Price, consideration of revenues received outside of the PJM energy and ancillary services markets is allowed, except to the extent revenues are associated with “Conditioned State Support or bilateral contracts that direct submission of an offer to lower RPM Auction clearing prices.”<sup>164</sup> This change reflects that not all out-of-PJM Markets revenues are improper, but rather may reflect resource attributes not compensated through the capacity, energy, or ancillary services markets. Such attributes could include environmental benefits, like RECs and ZECs. In addition, resources for which energy production is a byproduct of a resource owner’s primary economic interest in the facility (e.g., landfill gas, wood waste, municipal solid waste, black liquor, coal mine gas, or distillate fuel oil) could

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<sup>164</sup> Proposed Tariff, Attachment DD, section 5.14(h-2)(4)(B) and (C).

include all revenues with the owner's primary business. In short, the unit-specific floor price determination would exclude only those dollars associated with impermissible behavior.

Third, as discussed, PJM is proposing to allow sellers of resources undergoing a fact-specific review for Buyer-Side Market Power to request a unit-specific MOPR Floor Offer Price.<sup>165</sup> Given that (1) such resources may be subject to the MOPR, (2) PJM or the IMM may initiate the fact-specific review as late as 135 days before the RPM Auction, and (3) unit-specific exception requests are due 120 days before the RPM Auction, a seller may not know whether the resource will be subject to the MOPR before unit-specific requests are due. Thus, a prudent seller of a resource with costs below the applicable default MOPR Floor Offer Price may wish to seek a unit-specific price in case the resource is subject to the MOPR. Of course, such floor price would not be binding unless PJM determines that the resource is subject to the MOPR.

Fourth, PJM proposes to allow a unit-specific exception even if the seller is unable to support each claimed cost advantage. Under the existing language, an exception request could be denied in its entirety if a seller fails to adequately support its claimed cost and revenues.<sup>166</sup> Because there are many costs and revenues to be considered in a unit-specific request, it would be overly harsh to deny a request simply because a single cost element was not adequately supported. Accordingly, PJM proposes that, in the event an element is

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<sup>165</sup> Proposed Tariff, Attachment DD, section 5.14(h-2)(4) (“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)(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 Capacity Resource.”).

<sup>166</sup> See proposed Tariff, Attachment DD, section 5.14(h-1)(3)(D).

unsupported, that unsupported element will not be considered in the unit-specific offer floor determination.<sup>167</sup>

Finally, because the focused MOPR does not apply to Demand Resources and Energy Efficiency Resources, PJM is not including language related to determining floor prices for such resources.<sup>168</sup>

#### **IV. PJM STAKEHOLDER PROCESS AND BOARD AUTHORIZATION**

To address the concerns with the Expanded MOPR discussed above, the PJM Board initiated an expedited “Critical Issue Fast Path” process for stakeholders to address the MOPR and its future application in the capacity market on April 6, 2021.<sup>169</sup> In its letter, the PJM Board underscored its desire for PJM stakeholders to reach consensus on any changes to the MOPR. To that end, PJM convened a total of nine productive discussions to consider alternative options to the Expanded MOPR culminating in a final advisory vote by the Members Committee. On June 30, 2021, the PJM Members Committee voted on nine distinct packages sponsored by various parties designed to address the concerns with the Expanded MOPR. In the end, the Members Committee overwhelmingly supported one package, which was PJM’s MOPR solution with a sector-weighted endorsement of 4.175 out of 5. None of the other packages received greater than the two-thirds sector weighted endorsement typically required for approval.

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<sup>167</sup> See proposed Tariff, Attachment DD, section 5.14(h)-(3)(D) (“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.”).

<sup>168</sup> See Attachment G – Comparison of section Focused MOPR default and unit-specific MOPR Floor Offer Prices determinations against Expanded MOPR default and unit-specific MOPR Floor Offer Prices determinations.

<sup>169</sup> See April 6, 2021 PJM Board Letter.

Upon the conclusion of the Members Committee endorsement, the Board discussed and considered several of the other packages as well as individual topics, including but not limited to: requests to delay filing MOPR reform, Net CONE as compared to Net ACR as the basis of the MOPR, creation of an emerging technologies MOPR exemption, considerations related to self-supply proposals, and increased reporting on auction results. Ultimately, however, given the overwhelming stakeholder support for the PJM package and the fact that any amendments to the PJM proposal may have otherwise altered Members' votes, the PJM Board of Managers authorized PJM to make this filing under section 205 of the FPA without modification.<sup>170</sup>

#### **V. EFFECTIVE DATE AND IMPLEMENTATION TIMELINE**

PJM requests an effective date of September 28, 2021, for the proposed Tariff revisions, which is 60 days from the date of filing. If accepted, the proposed MOPR in this filing would become effective and utilized for the 2023/2024 Base Residual Auction.

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<sup>170</sup> PJM Board Letter, PJM Interconnection, L.L.C. (July 7, 2021), <https://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/20210708-board-letter-communicating-critical-issue-fast-path-minimum-offer-price-rule-decision.ashx>.

## **VI. COMMUNICATIONS**

PJM requests that all communications regarding this filing be directed to the following persons:

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## **VII. DOCUMENTS INCLUDED WITH THIS FILING**

In accordance with the requirements of Order No. 714<sup>171</sup> and the Commission's eTariff regulations, PJM hereby submits an eTariff XML filing package consisting of the following materials:

1. This transmittal letter;
2. Attachment A – Revisions to the Tariff (marked);
3. Attachment B – Revisions to the Tariff (clean);
4. Attachment C – Affidavit of Peter Cramton on behalf of PJM Interconnection, L.L.C.;

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<sup>171</sup> *Electronic Tariff Filings*, Order No. 714, 124 FERC ¶ 61,270 (2008), *final rule*, Order No. 714-A, 147 FERC ¶ 61,115 (2014).

5. Attachment D – Affidavit of Adam J. Keech on behalf of PJM Interconnection, L.L.C.;
6. Attachment E – Affidavit of Dr. Walter F. Graf on behalf of PJM Interconnection, L.L.C.;
7. Attachment F – Affidavit of Lisa Morelli on behalf of PJM Interconnection, L.L.C.; and
8. Attachment G – Comparison of section Focused MOPR default and unit-specific MOPR Floor Offer Prices determinations against Expanded MOPR default and unit-specific MOPR Floor Offer Prices determinations.

### **VIII. 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,<sup>172</sup> PJM will post a copy of this filing to the FERC filings section of its internet site, located at the following link: <http://www.pjm.com/documents/ferc-manuals.aspx> with a specific link to the newly-filed document, and will send an email on the same date as this filing to all PJM Members and all state utility regulatory commissions in the PJM Region<sup>173</sup> alerting them that this filing has been made by PJM today, and is available by following such link.

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<sup>172</sup> See 18 C.F.R §§ 35.2(e) and 385.2010(f)(3).

<sup>173</sup> PJM already maintains, updates, and regularly uses email lists for all PJM members and affected commissions.



## **IX. CONCLUSION**

In accordance with the foregoing, PJM respectfully requests that the Commission accept the proposed revisions to the Tariff effective as of September 28, 2021, as discussed herein.

Respectfully submitted,

/s/ Chenchao Lu

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*On behalf of  
PJM Interconnection, L.L.C.*

# Attachment A

## Revisions to the PJM Open Access Transmission Tariff

(Marked/Redline Format)

## **Definitions – A - B**

### **Abnormal Condition:**

“Abnormal Condition” shall mean any condition on the Interconnection Facilities which, determined in accordance with Good Utility Practice, is: (i) outside normal operating parameters such that facilities are operating outside their normal ratings or that reasonable operating limits have been exceeded; and (ii) could reasonably be expected to materially and adversely affect the safe and reliable operation of the Interconnection Facilities; but which, in any case, could reasonably be expected to result in an Emergency Condition. Any condition or situation that results from lack of sufficient generating capacity to meet load requirements or that results solely from economic conditions shall not, standing alone, constitute an Abnormal Condition.

### **Acceleration Request:**

“Acceleration Request” shall mean a request pursuant to Operating Agreement, Schedule 1, section 1.9.4A, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.9.4A, to accelerate or reschedule a transmission outage scheduled pursuant to Operating Agreement, Schedule 1, section 1.9.2 or Operating Agreement, Schedule 1, section 1.9.4, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.9.2 or Tariff, Attachment K-Appendix, section 1.9.4.

### **Additional Day-ahead Scheduling Reserves Requirement:**

“Additional Day-ahead Scheduling Reserves Requirement” shall mean the portion of the Day-ahead Scheduling Reserves Requirement that is required in addition to the Base Day-ahead Scheduling Reserves Requirement to ensure adequate resources are procured to meet real-time load and operational needs, as specified in the PJM Manuals.

### **Affected System:**

“Affected System” shall mean an electric system other than the Transmission Provider’s Transmission System that may be affected by a proposed interconnection or on which a proposed interconnection or addition of facilities or upgrades may require modifications or upgrades to the Transmission System.

### **Affected System Operator:**

“Affected System Operator” shall mean an entity that operates an Affected System or, if the Affected System is under the operational control of an independent system operator or a regional transmission organization, such independent entity.

### **Affiliate:**

“Affiliate” shall mean any two or more entities, one of which Controls the other or that are under common Control. “Control,” as that term is used in this definition, shall mean the possession, directly or indirectly, of the power to direct the management or policies of an entity. Ownership

of publicly-traded equity securities of another entity shall not result in Control or affiliation for purposes of the Tariff or Operating Agreement if the securities are held as an investment, the holder owns (in its name or via intermediaries) less than 10 percent (10%) of the outstanding securities of the entity, the holder does not have representation on the entity's board of directors (or equivalent managing entity) or vice versa, and the holder does not in fact exercise influence over day-to-day management decisions. Unless the contrary is demonstrated to the satisfaction of the Members Committee, Control shall be presumed to arise from the ownership of or the power to vote, directly or indirectly, ten percent or more of the voting securities of such entity.

**Agreements:**

“Agreements” shall mean the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C., the PJM Open Access Transmission Tariff, the Reliability Assurance Agreement, and/or other agreements between PJM Interconnection, L.L.C. and its Members.

**Ancillary Services:**

“Ancillary Services” shall mean those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider's Transmission System in accordance with Good Utility Practice.

**Annual Demand Resource:**

“Annual Demand Resource” shall have the meaning specified in the Reliability Assurance Agreement.

**Annual Energy Efficiency Resource:**

“Annual Energy Efficiency Resource” shall have the meaning specified in the Reliability Assurance Agreement.

**Annual Resource:**

“Annual Resource” shall mean a Generation Capacity Resource, an Annual Energy Efficiency Resource or an Annual Demand Resource.

**Annual Resource Price Adder:**

“Annual Resource Price Adder” shall mean, for Delivery Years starting June 1, 2014 and ending May 31, 2017, an addition to the marginal value of Unforced Capacity and the Extended Summer Resource Price Adder as necessary to reflect the price of Annual Resources required to meet the applicable Minimum Annual Resource Requirement.

**Annual Revenue Rate:**

“Annual Revenue Rate” shall mean the rate employed to assess a compliance penalty charge on a

Curtailed Service Provider under Tariff, Attachment DD, section 11.

**Annual Transmission Costs:**

“Annual Transmission Costs” shall mean the total annual cost of the Transmission System for purposes of Network Integration Transmission Service shall be the amount specified in Attachment H for each Zone until amended by the applicable Transmission Owner or modified by the Commission.

**Applicable Laws and Regulations:**

“Applicable Laws and Regulations” shall mean all duly promulgated applicable federal, State and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority having jurisdiction over the relevant parties, their respective facilities, and/or the respective services they provide.

**Applicable Regional Entity:**

“Applicable Regional Entity” shall mean the Regional Entity for the region in which a Network Customer, Transmission Customer, New Service Customer, or Transmission Owner operates.

**Applicable Standards:**

“Applicable Standards” shall mean the requirements and guidelines of NERC, the Applicable Regional Entity, and the Control Area in which the Customer Facility is electrically located; the PJM Manuals; and Applicable Technical Requirements and Standards.

**Applicable Technical Requirements and Standards:**

“Applicable Technical Requirements and Standards” shall mean those certain technical requirements and standards applicable to interconnections of generation and/or transmission facilities with the facilities of an Interconnected Transmission Owner or, as the case may be and to the extent applicable, of an Electric Distributor, as published by Transmission Provider in a PJM Manual provided, however, that, with respect to any generation facilities with maximum generating capacity of 2 MW or less (synchronous) or 5 MW or less (inverter-based) for which the Interconnection Customer executes a Construction Service Agreement or Interconnection Service Agreement on or after March 19, 2005, “Applicable Technical Requirements and Standards” shall refer to the “PJM Small Generator Interconnection Applicable Technical Requirements and Standards.” All Applicable Technical Requirements and Standards shall be publicly available through postings on Transmission Provider’s internet website.

**Applicant:**

“Applicant” shall mean an entity desiring to become a PJM Member, become a Market Participant, engage in market activities, or to take Transmission Service that has submitted the

PJMSettlement credit application, PJMSettlement credit agreement and other required submittals as set forth in Tariff, Attachment Q.

**Application:**

“Application” shall mean a request by an Eligible Customer for transmission service pursuant to the provisions of the Tariff.

**Attachment Facilities:**

“Attachment Facilities” shall mean the facilities necessary to physically connect a Customer Facility to the Transmission System or interconnected distribution facilities.

**Attachment H:**

“Attachment H” shall refer collectively to the Attachments to the PJM Tariff with the prefix “H” that set forth, among other things, the Annual Transmission Rates for Network Integration Transmission Service in the PJM Zones.

**Auction Revenue Rights:**

“Auction Revenue Rights” or “ARRs” shall mean the right to receive the revenue from the Financial Transmission Right auction, as further described in Operating Agreement, Schedule 1, section 7.4, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.

**Auction Revenue Rights Credits:**

“Auction Revenue Rights Credits” shall mean the allocated share of total FTR auction revenues or costs credited to each holder of Auction Revenue Rights, calculated and allocated as specified in Operating Agreement, Schedule 1, section 7.4.3, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.3.

**Authorized Government Agency:**

“Authorized Government Agency” means a regulatory body or government agency, with jurisdiction over PJM, the PJM Market, or any entity doing business in the PJM Market, including, but not limited to, the Commission, State Commissions, and state and federal attorneys general.

**Avoidable Cost Rate:**

“Avoidable Cost Rate” shall mean a component of the Market Seller Offer Cap calculated in accordance with Tariff, Attachment DD, section 6.

**Balancing Congestion Charges:**

“Balancing Congestion Charges” shall be equal to the sum of congestion charges collected from Market Participants that are purchasing energy in the Real-time Energy Market minus [the sum of congestion charges paid to Market Participants that are selling energy in the Real-time Energy Market plus any congestion charges calculated pursuant to the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38), plus any congestion charges calculated pursuant to the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 45), plus any congestion charges calculated pursuant to agreements between the Office of the Interconnection and other entities, plus any charges or credits calculated pursuant to Operating Agreement, Schedule 1, section 3.8, and the parallel provisions of Tariff, Attachment K-Appendix, section 3.8, as applicable)].

**Balancing Ratio:**

“Balancing Ratio” shall have the meaning provided in Tariff, Attachment DD, section 10A.

**Base Capacity Demand Resource:**

“Base Capacity Demand Resource” shall have the meaning specified in the Reliability Assurance Agreement.

**Base Capacity Demand Resource Constraint:**

“Base Capacity Demand Resource Constraint” for the PJM Region or an LDA, shall mean, for the 2018/2019 and 2019/2020 Delivery Years, the maximum Unforced Capacity amount, determined by PJM, of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources that is consistent with the maintenance of reliability. As more fully set forth in the PJM Manuals, PJM calculates the Base Capacity Demand Resource Constraint for the PJM Region or an LDA, by first determining a reference annual loss of load expectation (“LOLE”) assuming no Base Capacity Resources, including no Base Capacity Demand Resources or Base Capacity Energy Efficiency Resources. The calculation for the PJM Region uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast and iteratively shifting the load distributions to result in the Installed Reserve Margin established for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). The calculation for each relevant LDA uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). For the relevant LDA calculation, the weekly capacity distributions are adjusted to reflect the Capacity Emergency Transfer Limit for the Delivery Year in question.

For both the PJM Region and LDA analyses, PJM then models the commitment of varying amounts of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources (displacing otherwise committed generation) as interruptible from June 1 through September 30

and unavailable the rest of the Delivery Year in question and calculates the LOLE at each DR and EE level. The Base Capacity Demand Resource Constraint is the combined amount of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources, stated as a percentage of the unrestricted annual peak load, that produces no more than a five percent increase in the LOLE, compared to the reference value. The Base Capacity Demand Resource Constraint shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

**Base Capacity Demand Resource Price Decrement:**

“Base Capacity Demand Resource Price Decrement” shall mean, for the 2018/2019 and 2019/2020 Delivery Years, a difference between the clearing price for Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources and the clearing price for Base Capacity Resources and Capacity Performance Resources, representing the cost to procure additional Base Capacity Resources or Capacity Performance Resources out of merit order when the Base Capacity Demand Resource Constraint is binding.

**Base Capacity Energy Efficiency Resource:**

“Base Capacity Energy Efficiency Resource” shall have the meaning specified in the Reliability Assurance Agreement.

**Base Capacity Resource:**

“Base Capacity Resource” shall mean a Capacity Resource as described in Tariff, Attachment DD, section 5.5A(b).

**Base Capacity Resource Constraint:**

“Base Capacity Resource Constraint” for the PJM Region or an LDA, shall mean, for the 2018/2019 and 2019/2020 Delivery Years, the maximum Unforced Capacity amount, determined by PJM, of Base Capacity Resources, including Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources, that is consistent with the maintenance of reliability. As more fully set forth in the PJM Manuals, PJM calculates the above Base Capacity Resource Constraint for the PJM Region or an LDA, by first determining a reference annual loss of load expectation (“LOLE”) assuming no Base Capacity Resources, including no Base Capacity Demand Resources or Base Capacity Energy Efficiency Resources. The calculation for the PJM Region uses the weekly load distribution from the Installed Reserve Margin study for the Delivery Year in question (based on the most recent load forecast and iteratively shifting the load distributions to result in the Installed Reserve Margin established for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). The calculation for each relevant LDA uses a weekly load distribution (based on the Installed Reserve Margin study and the most recent load forecast for the Delivery Year in



question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). For the relevant LDA calculation, the weekly capacity distributions are adjusted to reflect the Capacity Emergency Transfer Limit for the Delivery Year in question. Additionally, for the PJM Region and relevant LDA calculation, the weekly capacity distributions are adjusted to reflect winter ratings.

For both the PJM Region and LDA analyses, PJM models the commitment of an amount of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources equal to the Base Capacity Demand Resource Constraint (displacing otherwise committed generation). PJM then models the commitment of varying amounts of Base Capacity Resources (displacing otherwise committed generation) as unavailable during the peak week of winter and available the rest of the Delivery Year in question and calculates the LOLE at each Base Capacity Resource level. The Base Capacity Resource Constraint is the combined amount of Base Capacity Demand Resources, Base Capacity Energy Efficiency Resources and Base Capacity Resources, stated as a percentage of the unrestricted annual peak load, that produces no more than a ten percent increase in the LOLE, compared to the reference value. The Base Capacity Resource Constraint shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [one minus the pool-wide average EFORD] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

**Base Capacity Resource Price Decrement:**

“Base Capacity Resource Price Decrement” shall mean, for the 2018/2019 and 2019/2020 Delivery Years, a difference between the clearing price for Base Capacity Resources and the clearing price for Capacity Performance Resources, representing the cost to procure additional Capacity Performance Resources out of merit order when the Base Capacity Resource Constraint is binding.

**Base Day-ahead Scheduling Reserves Requirement:**

“Base Day-ahead Scheduling Reserves Requirement” shall mean the thirty-minute reserve requirement for the PJM Region established consistent with the Applicable Standards, plus any additional thirty-minute reserves scheduled in response to an RTO-wide Hot or Cold Weather Alert or other reasons for conservative operations.

**Base Load Generation Resource**

“Base Load Generation Resource” shall mean a Generation Capacity Resource that operates at least 90 percent of the hours that it is available to operate, as determined by the Office of the Interconnection in accordance with the PJM Manuals.

**Base Offer Segment:**

“Base Offer Segment” shall mean a component of a Sell Offer based on an existing Generation

Capacity Resource, equal to the Unforced Capacity of such resource, as determined in accordance with the PJM Manuals. If the Sell Offers of multiple Market Sellers are based on a single Existing Generation Capacity Resource, the Base Offer Segments of such Market Sellers shall be determined pro rata based on their entitlements to Unforced Capacity from such resource.

**Base Residual Auction:**

“Base Residual Auction” shall mean the auction conducted three years prior to the start of the Delivery Year to secure commitments from Capacity Resources as necessary to satisfy any portion of the Unforced Capacity Obligation of the PJM Region not satisfied through Self-Supply.

**Batch Load Demand Resource:**

“Batch Load Demand Resource” shall mean a Demand Resource that has a cyclical production process such that at most times during the process it is consuming energy, but at consistent regular intervals, ordinarily for periods of less than ten minutes, it reduces its consumption of energy for its production processes to minimal or zero megawatts.

**Behind The Meter Generation:**

“Behind The Meter Generation” shall refer to a generation unit that delivers energy to load without using the Transmission System or any distribution facilities (unless the entity that owns or leases the distribution facilities has consented to such use of the distribution facilities and such consent has been demonstrated to the satisfaction of the Office of the Interconnection); provided, however, that Behind The Meter Generation does not include (i) at any time, any portion of such generating unit’s capacity that is designated as a Generation Capacity Resource; or (ii) in an hour, any portion of the output of such generating unit that is sold to another entity for consumption at another electrical location or into the PJM Interchange Energy Market.

**Black Start Service:**

“Black Start Service” shall mean the capability of generating units to start without an outside electrical supply or the demonstrated ability of a generating unit with a high operating factor (subject to Transmission Provider concurrence) to automatically remain operating at reduced levels when disconnected from the grid.

**Border Yearly Charge:**

“Border Yearly Charge” shall mean the yearly charge determined in accordance with Tariff, Schedule 7.

**Breach:**

“Breach” shall mean the failure of a party to perform or observe any material term or condition

of Tariff, Part IV or Tariff, Part VI, or any agreement entered into thereunder as described in the relevant provisions of such agreement.

**Breaching Party:**

“Breaching Party” shall mean a party that is in Breach of Tariff, Part IV or Tariff, Part VI and/or an agreement entered into thereunder.

**Business Day:**

“Business Day” shall mean a day in which the Federal Reserve System is open for business and is not a scheduled PJM holiday.

**Buy Bid:**

“Buy Bid” shall mean a bid to buy Capacity Resources in any Incremental Auction.

**Buyer-Side Market Power:**

“Buyer-Side Market Power” shall mean the ability of Capacity Market Sellers with a Load Interest to suppress RPM Auction clearing prices for the overall benefit of their (and/or affiliates) portfolio of generation and load.

## **Definitions – C-D**

### **Canadian Guaranty:**

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

### **Cancellation Costs:**

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

### **Capacity:**

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

### **Capacity Emergency Transfer Limit:**

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

### **Capacity Emergency Transfer Objective:**

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

### **Capacity Export Transmission Customer:**

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

### **Capacity Import Limit:**

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

### **Capacity Interconnection Rights:**

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

**Capacity Market Buyer:**

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

**Capacity Market Seller:**

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

**Capacity Performance Resource:**

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

**Capacity Performance Transition Incremental Auction:**

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

**Capacity Resource:**

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

**Capacity Resource with State Subsidy:**

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

**Capacity Resource Clearing Price:**

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

**Capacity Storage Resource:**

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

**Capacity Transfer Right:**

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

**Capacity Transmission Injection Rights:**

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

**Charge Economic Maximum Megawatts:**

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

**Charge Economic Minimum Megawatts:**

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

**Charge Mode:**

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

**Charge Ramp Rate:**

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

**Cleared Capacity Resource with State Subsidy:**

“Cleared Capacity Resource with State Subsidy” shall mean a Capacity Resource with State Subsidy that has cleared in an RPM Auction for a Delivery Year that is prior to the 2022/2023 Delivery Year or, starting with 2022/2023 Delivery Year, the MWs (in installed capacity) comprising a Capacity Resource with State Subsidy that have cleared an RPM Auction pursuant to its Sell Offer at or above its resource-specific MOPR Floor Offer Price or the applicable default New Entry MOPR Floor Offer Price and since then, any of those MWs (in installed capacity) comprising a Capacity Resource with State Subsidy have been, the subject of a Sell Offer into the Base Residual Auction or included in an FRR Capacity Plan at the time of the Base Residual Auction for the relevant Delivery Year.

**Cold/Warm/Hot Notification Time:**

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

**Cold/Warm/Hot Start-up Time:**

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

engines or systems, maintaining stable fuel/air ratios, and other auxiliary equipment necessary for startup.

**Cold Weather Alert:**

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

**Collateral:**

“Collateral” shall be a cash deposit, including any interest thereon, or a Letter of Credit issued for the benefit of PJM or PJMSettlement, in an amount and form determined by and acceptable to PJM or PJMSettlement, provided by a Participant to PJM or PJMSettlement as credit support in order to participate in the PJM Markets or take Transmission Service. “Collateral” shall also include surety bonds, except for the purpose of satisfying the FTR Credit Requirement, in which case only a cash deposit or Letter of Credit will be acceptable.

**Collateral Call:**

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

**Commencement Date:**

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

**Committed Offer:**

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

**Completed Application:**

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

**Compliance Aggregation Area (CAA):**



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

**Composite Energy Offer:**

“Composite Energy Offer” for generation resources shall mean the sum (in \$/MWh) of the Incremental Energy Offer and amortized Start-Up Costs and amortized No-load Costs, and for Economic Load Response Participant resources the sum (in \$/MWh) of the Incremental Energy Offer and amortized shutdown costs, as determined in accordance with Tariff, Attachment K-Appendix, section 2.4 and Tariff, Attachment K-Appendix, section 2.4A and the PJM Manuals.

**Conditional Incremental Auction:**

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

**Conditioned State Support:**

“Conditioned State Support” shall mean any financial benefit required or incentivized by a state, or political subdivision of a state acting in its sovereign capacity, that is provided outside of PJM Markets and in exchange for the sale of a FERC-jurisdictional product conditioned on clearing in any RPM Auction, where “conditioned on clearing in any RPM Auction” refers to specific directives as to the level of the offer that must be entered for the relevant Generation Capacity Resource in the RPM Auction or directives that the Generation Capacity Resource is required to clear in any RPM Auction. Conditioned State Support shall not include any Legacy Policy.

**CONE Area:**

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

**Confidential Information:**

“Confidential Information” shall mean any confidential, proprietary, or trade secret information of a plan, specification, pattern, procedure, design, device, list, concept, policy, or compilation relating to the present or planned business of a New Service Customer, Transmission Owner, or other Interconnection Party or Construction Party, which is designated as confidential by the party supplying the information, whether conveyed verbally, electronically, in writing, through

inspection, or otherwise, and shall include, without limitation, all information relating to the producing party's technology, research and development, business affairs and pricing, and any information supplied by any New Service Customer, Transmission Owner, or other Interconnection Party or Construction Party to another such party prior to the execution of an Interconnection Service Agreement or a Construction Service Agreement.

**Congestion Price:**

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

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

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

**Constraint Relaxation Logic:**

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

**Constructing Entity:**

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

**Construction Party:**

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

**Construction Service Agreement:**

“Construction Service Agreement” shall mean either an Interconnection Construction Service Agreement or an Upgrade Construction Service Agreement.

**Contingent Facilities:**

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

**Continuous Mode:**

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

**Control Area:**

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

- (1) match the power output of the generators within the electric power system(s) and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);
- (2) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;
- (3) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and
- (4) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

**Control Zone:**

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

**Controllable A.C. Merchant Transmission Facilities:**

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

**Coordinated External Transaction:**

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

**Coordinated Transaction Scheduling:**

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

**Corporate Guaranty:**

“Corporate Guaranty” shall mean a legal document, in a form acceptable to PJM and/or PJMSettlement, used by a Credit Affiliate of an entity to guaranty the obligations of another entity.

**Cost of New Entry:**

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

**Costs:**

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

**Counterparty:**

“Counterparty” shall mean PJMSettlement as the contracting party, in its name and own right and not as an agent, to an agreement or transaction with a Market Participant or other entities, including the agreements and transactions with customers regarding transmission service and other transactions under the PJM Tariff and the Operating Agreement. PJMSettlement shall not

be a counterparty to (i) any bilateral transactions between Members, or (ii) any Member's self-supply of energy to serve its load, or (iii) any Member's self-schedule of energy reported to the Office of the Interconnection to the extent that energy serves that Member's own load.

**Credit Affiliate:**

"Credit Affiliate" shall mean Principals, corporations, partnerships, firms, joint ventures, associations, joint stock companies, trusts, unincorporated organizations or entities, one of which directly or indirectly controls the other or that are both under common Control. "Control," as that term is used in this definition, shall mean the possession, directly or indirectly, of the power to direct the management or policies of a person or an entity.

**Credit Available for Export Transactions:**

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

**Credit Available for Virtual Transactions:**

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

**Credit Breach:**

"Credit Breach" shall mean (a) the failure of a Participant to perform, observe, meet or comply with any requirements of Tariff, Attachment Q or other provisions of the Agreements, other than a Financial Default, or (b) a determination by PJM and notice to the Participant that a Participant represents an unreasonable credit risk to the PJM Markets; that, in either event, has not been cured or remedied after any required notice has been given and any cure period has elapsed.

**Credit-Limited Offer:**

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

**Credit Support Default:**

"Credit Support Default," shall mean (a) the failure of any Guarantor of a Market Participant to make any payment, or to perform, observe, meet or comply with any provisions of the applicable

Guaranty or Credit Support Document that has not been cured or remedied, after any required notice has been given and an opportunity to cure (if any) has elapsed, (b) a representation made or deemed made by a Guarantor in any Credit Support Document that proves to be false, incorrect or misleading in any material respect when made or deemed made, (c) the failure of a Guaranty or other Credit Support Document to be in full force and effect prior to the satisfaction of all obligations of such Participant to PJM, without PJM's consent, or (d) a Guarantor repudiating, disaffirming, disclaiming or rejecting, in whole or in part, its obligations under the Guaranty or challenging the validity of the Guaranty.

**Credit Support Document:**

“Credit Support Document” shall mean any agreement or instrument in any way guaranteeing or securing any or all of a Participant's obligations under the Agreements (including, without limitation, the provisions of Tariff, Attachment Q), any agreement entered into under, pursuant to, or in connection with the Agreements or any agreement entered into under, pursuant to, or in connection with the Agreements and/or any other agreement to which PJM, PJMSettlement and the Participant are parties, including, without limitation, any Corporate Guaranty, Letter of Credit, or agreement granting PJM and PJMSettlement a security interest.

**CTS Enabled Interface:**

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

**CTS Interface Bid:**

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

**Curtailement:**

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

**Curtailement Service Provider:**

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

**Customer Facility:**

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

**Customer-Funded Upgrade:**

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

**Customer Interconnection Facilities:**

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

**Daily Deficiency Rate:**

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

**Daily Unforced Capacity Obligation:**

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

**Day-ahead Congestion Price:**

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

**Day-ahead Energy Market:**

“Day-ahead Energy Market” shall mean the schedule of commitments for the purchase or sale of energy and payment of Transmission Congestion Charges developed by the Office of the Interconnection as a result of the offers and specifications submitted in accordance with Operating Agreement, Schedule 1, section 1.10 and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.

**Day-ahead Energy Market Injection Congestion Credits:**

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

**Day-ahead Energy Market Transmission Congestion Charges:**

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

**Day-ahead Energy Market Withdrawal Congestion Charges:**

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

**Day-ahead Loss Price:**

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

**Day-ahead Prices:**

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



**Day-Ahead Pseudo-Tie Transaction:**

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

**Day-ahead Scheduling Reserves:**

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

**Day-ahead Scheduling Reserves Market:**

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

**Day-ahead Scheduling Reserves Requirement:**

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

**Day-ahead Scheduling Reserves Resources:**

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

**Day-ahead Settlement Interval:**

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

**Day-ahead System Energy Price:**

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

**Deactivation:**

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

**Deactivation Avoidable Cost Credit:**

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

**Deactivation Avoidable Cost Rate:**

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

**Deactivation Date:**

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

**Decrement Bid:**

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

**Default:**

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

**Delivering Party:**

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

**Delivery Year:**

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

**Demand Bid:**

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

**Demand Bid Limit:**

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

**Demand Bid Screening:**

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

**Demand Resource:**

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

**Demand Resource Factor or DR Factor:**

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

**Designated Agent:**

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

**Designated Entity:**

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

**Direct Assignment Facilities:**

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

**Direct Charging Energy:**

“Direct Charging Energy” shall mean the energy that an Energy Storage Resource purchases from the PJM Interchange Energy Market and (i) later resells to the PJM Interchange Energy Market; or (ii) is lost to conversion inefficiencies, provided that such inefficiencies are an

unavoidable component of the conversion, storage, and discharge process that is used to resell energy back to the PJM Interchange Energy Market.

**Direct Load Control:**

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

**Discharge Economic Maximum Megawatts:**

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

**Discharge Economic Minimum Megawatts:**

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

**Discharge Mode:**

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

**Discharge Ramp Rate:**

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

**Dispatch Rate:**

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

**Dispatched Charging Energy:**

“Dispatched Charging Energy” shall mean Direct Charging Energy that an Energy Storage Resource Model Participant receives from the electric grid pursuant to PJM dispatch while providing one of the following services in the PJM markets: Energy Imbalance Service pursuant

to Tariff, Schedule 4; Regulation; Tier 2 Synchronized Reserves; or Reactive Service. Energy Storage Resource Model Participants shall be considered to be providing Energy Imbalance Service when they are dispatchable by PJM in real-time.

**Dynamic Schedule:**

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

**Dynamic Transfer:**

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

## **Definitions – E - F**

### **Economic-based Enhancement or Expansion:**

“Economic-based Enhancement or Expansion” shall have the same meaning provided in the Operating Agreement.

### **Economic Load Response Participant:**

“Economic Load Response Participant” shall mean a Member or Special Member that qualifies under Operating Agreement, Schedule 1, section 1.5A, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.5A, to participate in the PJM Interchange Energy Market and/or Ancillary Services markets through reductions in demand.

### **Economic Maximum:**

“Economic Maximum” shall mean the highest incremental MW output level, submitted to PJM market systems by a Market Participant, that a unit can achieve while following economic dispatch.

### **Economic Minimum:**

“Economic Minimum” shall mean the lowest incremental MW output level, submitted to PJM market systems by a Market Participant, that a unit can achieve while following economic dispatch.

### **Effective FTR Holder:**

“Effective FTR Holder” shall mean:

- (i) For an FTR Holder that is either a (a) privately held company, or (b) a municipality or electric cooperative, as defined in the Federal Power Act, such FTR Holder, together with any Affiliate, subsidiary or parent of the FTR Holder, any other entity that is under common ownership, wholly or partly, directly or indirectly, or has the ability to influence, directly or indirectly, the management or policies of the FTR Holder; or
- (ii) For an FTR Holder that is a publicly traded company including a wholly owned subsidiary of a publicly traded company, such FTR Holder, together with any Affiliate, subsidiary or parent of the FTR Holder, any other PJM Member has over 10% common ownership with the FTR Holder, wholly or partly, directly or indirectly, or has the ability to influence, directly or indirectly, the management or policies of the FTR Holder; or
- (iii) an FTR Holder together with any other PJM Member, including also any Affiliate, subsidiary or parent of such other PJM Member, with which it shares common ownership, wholly or partly, directly or indirectly, in any third entity which is a PJM Member (e.g., a joint venture).

**EFORd:**

“EFORd” shall have the meaning specified in the PJM Reliability Assurance Agreement.

**Electrical Distance:**

“Electrical Distance” shall mean, for a Generation Capacity Resource geographically located outside the metered boundaries of the PJM Region, the measure of distance, based on impedance and in accordance with the PJM Manuals, from the Generation Capacity Resource to the PJM Region.

**Eligible Customer:**

“Eligible Customer” shall mean:

(i) Any electric utility (including any Transmission Owner and any power marketer), Federal power marketing agency, or any person generating electric energy for sale for resale is an Eligible Customer under the Tariff. Electric energy sold or produced by such entity may be electric energy produced in the United States, Canada or Mexico. However, with respect to transmission service that the Commission is prohibited from ordering by Section 212(h) of the Federal Power Act, such entity is eligible only if the service is provided pursuant to a state requirement that the Transmission Provider or Transmission Owner offer the unbundled transmission service, or pursuant to a voluntary offer of such service by a Transmission Owner.

(ii) Any retail customer taking unbundled transmission service pursuant to a state requirement that the Transmission Provider or a Transmission Owner offer the transmission service, or pursuant to a voluntary offer of such service by a Transmission Owner, is an Eligible Customer under the Tariff. As used in Tariff, Part VI, Eligible Customer shall mean only those Eligible Customers that have submitted a Completed Application.

**Eligible Fast-Start Resource:**

“Eligible Fast-Start Resource” shall mean a Fast-Start Resource that is eligible for the application of Integer Relaxation during the calculation of Locational Marginal Prices as set forth in Tariff, Attachment K-Appendix, section 2.2.

**Emergency Action:**

“Emergency Action” shall mean any emergency action for locational or system-wide capacity shortages that either utilizes pre-emergency mandatory load management reductions or other emergency capacity, or initiates a more severe action including, but not limited to, a Voltage Reduction Warning, Voltage Reduction Action, Manual Load Dump Warning, or Manual Load Dump Action.

**Emergency Condition:**

“Emergency Condition” shall mean a condition or situation (i) that in the judgment of any Interconnection Party is imminently likely to endanger life or property; or (ii) that in the judgment of the Interconnected Transmission Owner or Transmission Provider is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Transmission System, the Interconnection Facilities, or the transmission systems or distribution systems to which the Transmission System is directly or indirectly connected; or (iii) that in the judgment of Interconnection Customer is imminently likely (as determined in a non-discriminatory manner) to cause damage to the Customer Facility or to the Customer Interconnection Facilities. System restoration and black start shall be considered Emergency Conditions, provided that a Generation Interconnection Customer is not obligated by an Interconnection Service Agreement to possess black start capability. Any condition or situation that results from lack of sufficient generating capacity to meet load requirements or that results solely from economic conditions shall not constitute an Emergency Condition, unless one or more of the enumerated conditions or situations identified in this definition also exists.

**Emergency Load Response Program:**

“Emergency Load Response Program” shall mean the program by which Curtailment Service Providers may be compensated by PJM for Demand Resources that will reduce load when dispatched by PJM during emergency conditions, and is described in Operating Agreement, Schedule 1, section 8 and the parallel provisions of Tariff, Attachment K-Appendix, section 8.

**Energy Efficiency Resource:**

“Energy Efficiency Resource” shall have the meaning specified in the PJM Reliability Assurance Agreement.

**Energy Market Opportunity Cost:**

“Energy Market Opportunity Cost” shall mean the difference between (a) the forecasted cost to operate a specific generating unit when the unit only has a limited number of available run hours due to limitations imposed on the unit by Applicable Laws and Regulations, and (b) the forecasted future Locational Marginal Price at which the generating unit could run while not violating such limitations. Energy Market Opportunity Cost therefore is the value associated with a specific generating unit’s lost opportunity to produce energy during a higher valued period of time occurring within the same compliance period, which compliance period is determined by the applicable regulatory authority and is reflected in the rules set forth in PJM Manual 15. Energy Market Opportunity Costs shall be limited to those resources which are specifically delineated in Operating Agreement, Schedule 2.

**Energy Resource:**

“Energy Resource” shall mean a Generating Facility that is not a Capacity Resource.



**Energy Settlement Area:**

“Energy Settlement Area” shall mean the bus or distribution of busses that represents the physical location of Network Load and by which the obligations of the Network Customer to PJM are settled.

**Energy Storage Resource:**

“Energy Storage Resource” shall mean a resource capable of receiving electric energy from the grid and storing it for later injection to the grid that participates in the PJM Energy, Capacity and/or Ancillary Services markets as a Market Participant.

**Energy Storage Resource Model Participant:**

“Energy Storage Resource Model Participant” shall mean an Energy Storage Resource utilizing the Energy Storage Resource Participation Model.

**Energy Storage Resource Participation Model:**

“Energy Storage Resource Participation Model” shall mean the participation model accepted by the Commission in Docket No. ER19-469-000.

**Energy Transmission Injection Rights:**

“Energy Transmission Injection Rights” shall mean the rights to schedule energy deliveries at a specified point on the Transmission System. Energy Transmission Injection Rights may be awarded only to a Merchant D.C. Transmission Facility that connects the Transmission System to another control area. Deliveries scheduled using Energy Transmission Injection Rights have rights similar to those under Non-Firm Point-to-Point Transmission Service.

**Entity Providing Supply Services to Default Retail Service Provider:**

“Entity Providing Supply Services to Default Retail Service Provider” shall mean any entity, including but not limited to a load aggregator or power marketer, providing supply services to an electric distribution company when that electric distribution company is serving as the default retail service provider, and that enters into a contract or similar obligation with such electric distribution company to serve retail customers who have not selected a competitive retail service provider.

**Environmental Laws:**

“Environmental Laws” shall mean applicable Laws or Regulations relating to pollution or protection of the environment, natural resources or human health and safety.

**Environmentally-Limited Resource:**

“Environmentally-Limited Resource” shall mean a resource which has a limit on its run hours imposed by a federal, state, or other governmental agency that will significantly limit its availability, on either a temporary or long-term basis. This includes a resource that is limited by a governmental authority to operating only during declared PJM capacity emergencies.

**Equivalent Load:**

“Equivalent Load” shall mean the sum of a Market Participant’s net system requirements to serve its customer load in the PJM Region, if any, plus its net bilateral transactions.

**Event of Default:**

“Event of Default,” as that term is used in Tariff, Attachment Q, shall mean a Financial Default, Credit Breach, or Credit Support Default.

**Exercise of Buyer-Side Market Power:**

“Exercise of Buyer-Side Market Power” shall mean anti-competitive behavior of a Capacity Market Seller with a Load Interest, or directed by an entity with a Load Interest, to uneconomically lower RPM Auction Sell Offer(s) in order to suppress RPM Auction clearing prices for the overall benefit of the Capacity Market Seller’s (and/or affiliates of Capacity Market Seller) portfolio of generation and load or that of the directing entity with a Load Interest as determined pursuant to Tariff, Attachment DD, section 5.14(h-2)(2)(B). A bilateral contract between the Capacity Market Seller and an entity with a Load Interest with the express purpose of lowering capacity market clearing prices shall be evidence of the Exercise of Buyer-Side Market Power.

**Existing Generation Capacity Resource:**

“Existing Generation Capacity Resource” shall have the meaning specified in the Reliability Assurance Agreement.

**Export Credit Exposure:**

“Export Credit Exposure” is determined for each Market Participant for a given Operating Day, and shall mean the sum of credit exposures for the Market Participant’s Export Transactions for that Operating Day and for the preceding Operating Day.

**Export Nodal Reference Price:**

“Export Nodal Reference Price” at each location is the 97th percentile, shall be, the real-time hourly integrated price experienced over the corresponding two-month period in the preceding calendar year, calculated separately for peak and off-peak time periods. The two-month time periods used in this calculation shall be January and February, March and April, May and June, July and August, September and October, and November and December.

**Export Transaction:**

“Export Transaction” shall be a transaction by a Market Participant that results in the transfer of energy from within the PJM Control Area to outside the PJM Control Area. Coordinated External Transactions that result in the transfer of energy from the PJM Control Area to an adjacent Control Area are one form of Export Transaction.

**Export Transaction Price Factor:**

“Export Transaction Price Factor” for a prospective time interval shall be the greater of (i) PJM’s forecast price for the time interval, if available, or (ii) the Export Nodal Reference Price, but shall not exceed the Export Transaction’s dispatch ceiling price cap, if any, for that time interval. The Export Transaction Price Factor for a past time interval shall be calculated in the same manner as for a prospective time interval, except that the Export Transaction Price Factor may use a tentative or final settlement price, as available. If an Export Nodal Reference Price is not available for a particular time interval, PJM may use an Export Transaction Price Factor for that time interval based on an appropriate alternate reference price.

**Export Transaction Screening:**

“Export Transaction Screening” shall be the process PJM uses to review the Export Credit Exposure of Export Transactions against the Credit Available for Export Transactions, and deny or curtail all or a portion of an Export Transaction, if the credit required for such transactions is greater than the credit available for the transactions.

**Export Transactions Net Activity:**

“Export Transactions Net Activity” shall mean the aggregate net total, resulting from Export Transactions, of (i) Spot Market Energy charges, (ii) Transmission Congestion Charges, and (iii) Transmission Loss Charges, calculated as set forth in Operating Agreement, Schedule 1 and the parallel provisions of Tariff, Attachment K-Appendix. Export Transactions Net Activity may be positive or negative.

**Extended Primary Reserve Requirement:**

“Extended Primary Reserve Requirement” shall equal the Primary Reserve Requirement in a Reserve Zone or Reserve Sub-zone, plus 190 MW, plus any additional reserves scheduled under emergency conditions necessary to address operational uncertainty. The Extended Primary Reserve Requirement is calculated in accordance with the PJM Manuals.

**Extended Summer Demand Resource:**

“Extended Summer Demand Resource” shall have the meaning specified in the Reliability Assurance Agreement.

**Extended Summer Resource Price Adder:**

“Extended Summer Resource Price Adder” shall mean, for Delivery Years through May 31, 2018, an addition to the marginal value of Unforced Capacity as necessary to reflect the price of Annual Resources and Extended Summer Demand Resources required to meet the applicable Minimum Extended Summer Resource Requirement.

**Extended Synchronized Reserve Requirement:**

“Extended Synchronized Reserve Requirement” shall equal the Synchronized Reserve Requirement in a Reserve Zone or Reserve Sub-zone, plus 190 MW, plus any additional reserves scheduled under emergency conditions necessary to address operational uncertainty. The Extended Synchronized Reserve Requirement is calculated in accordance with the PJM Manuals.

**External Market Buyer:**

“External Market Buyer” shall mean a Market Buyer making purchases of energy from the PJM Interchange Energy Market for consumption by end-users outside the PJM Region, or for load in the PJM Region that is not served by Network Transmission Service.

**External Resource:**

“External Resource” shall mean a generation resource located outside the metered boundaries of the PJM Region.

**Facilities Study:**

“Facilities Study” shall be an engineering study conducted by the Transmission Provider (in coordination with the affected Transmission Owner(s)) to: (1) determine the required modifications to the Transmission Provider’s Transmission System necessary to implement the conclusions of the System Impact Study; and (2) complete any additional studies or analyses documented in the System Impact Study or required by PJM Manuals, and determine the required modifications to the Transmission Provider’s Transmission System based on the conclusions of such additional studies. The Facilities Study shall include the cost and scheduled completion date for such modifications, that will be required to provide the requested transmission service or to accommodate a New Service Request. As used in the Interconnection Service Agreement or Construction Service Agreement, Facilities Study shall mean that certain Facilities Study conducted by Transmission Provider (or at its direction) to determine the design and specification of the Customer Funded Upgrades necessary to accommodate the New Service Customer’s New Service Request in accordance with Tariff, Part VI, section 207.

**Fast-Start Resource:**

“Fast-Start Resource” shall have the meaning set forth in Tariff, Attachment K-Appendix, section 2.2A

**Federal Power Act:**

“Federal Power Act” shall mean the Federal Power Act, as amended, 16 U.S.C. §§ 791a, et seq.

**FERC or Commission:**

“FERC” or “Commission” shall mean the Federal Energy Regulatory Commission or any successor federal agency, commission or department exercising jurisdiction over the Tariff, Operating Agreement and Reliability Assurance Agreement.

**FERC Market Rules:**

“FERC Market Rules” mean the market behavior rules and the prohibition against electric energy market manipulation codified by the Commission in its Rules and Regulations at 18 CFR §§ 1c.2 and 35.37, respectively; the Commission-approved PJM Market Rules and any related proscriptions or any successor rules that the Commission from time to time may issue, approve or otherwise establish.

**Final Offer:**

“Final Offer” shall mean the offer on which a resource was dispatched by the Office of the Interconnection for a particular clock hour for the Operating Day.

**Final RTO Unforced Capacity Obligation:**

“Final RTO Unforced Capacity Obligation” shall mean the capacity obligation for the PJM Region, determined in accordance with RAA, Schedule 8.

**Financial Close:**

“Financial Close” shall mean the Capacity Market Seller has demonstrated that the Capacity Market Seller or its agent has completed the act of executing the material contracts and/or other documents necessary to (1) authorize construction of the project and (2) establish the necessary funding for the project under the control of an independent third-party entity. A sworn, notarized certification of an independent engineer certifying to such facts, and that the engineer has personal knowledge of, or has engaged in a diligent inquiry to determine, such facts, shall be sufficient to make such demonstration. For resources that do not have external financing, Financial Close shall mean the project has full funding available, and that the project has been duly authorized to proceed with full construction of the material portions of the project by the appropriate governing body of the company funding such project. A sworn, notarized certification by an officer of such company certifying to such facts, and that the officer has personal knowledge of, or has engaged in a diligent inquiry to determine, such facts, shall be sufficient to make such demonstration.

**Financial Default:**

“Financial Default” shall mean (a) the failure of a Member or Transmission Customer to make any payment for obligations under the Agreements when due, including but not limited to an invoice payment that has not been cured or remedied after notice has been given and any cure period has elapsed, (b) a bankruptcy proceeding filed by a Member, Transmission Customer or its Guarantor, or filed against a Member, Transmission Customer or its Guarantor and to which the Member, Transmission Customer or Guarantor, as applicable, acquiesces or that is not dismissed within 60 days, (c) a Member, Transmission Customer or its Guarantor, if any, is unable to meet its financial obligations as they become due, or (d) a Merger Without Assumption occurs in respect of the Member, Transmission Customer or any Guarantor of such Member or Transmission Customer.

**Financial Transmission Right:**

“Financial Transmission Right” or “FTR” shall mean a right to receive Transmission Congestion Credits as specified in Operating Agreement, Schedule 1, section 5.2.2 and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.2.

**Financial Transmission Right Obligation:**

“Financial Transmission Right Obligation” shall mean a right to receive Transmission Congestion Credits as specified in Operating Agreement, Schedule 1, section 5.2.2(b), and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.2(b).

**Financial Transmission Right Option:**

“Financial Transmission Right Option” shall mean a right to receive Transmission Congestion Credits as specified in Operating Agreement, Schedule 1, section 5.2.2(c), and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.2(c).

**Firm Point-To-Point Transmission Service:**

“Firm Point-To-Point Transmission Service” shall mean Transmission Service under the Tariff that is reserved and/or scheduled between specified Points of Receipt and Delivery pursuant to Tariff, Part II.

**Firm Transmission Feasibility Study:**

“Firm Transmission Feasibility Study” shall mean a study conducted by the Transmission Provider in accordance with Tariff, Part II, section 19.3 and Tariff, Part III, section 32.3.

**Firm Transmission Withdrawal Rights:**

“Firm Transmission Withdrawal Rights” shall mean the rights to schedule energy and capacity withdrawals from a Point of Interconnection of a Merchant Transmission Facility with the Transmission System. Firm Transmission Withdrawal Rights may be awarded only to a Merchant D.C. Transmission Facility that connects the Transmission System with another

control area. Withdrawals scheduled using Firm Transmission Withdrawal Rights have rights similar to those under Firm Point-to-Point Transmission Service.

**First Incremental Auction:**

“First Incremental Auction” shall mean an Incremental Auction conducted 20 months prior to the start of the Delivery Year to which it relates.

**Flexible Resource:**

“Flexible Resource” shall mean a generating resource that must have a combined Start-up Time and Notification Time of less than or equal to two hours; and a Minimum Run Time of less than or equal to two hours.

**Forecast Pool Requirement:**

“Forecast Pool Requirement” shall have the meaning specified in the Reliability Assurance Agreement.

**Foreign Guaranty:**

“Foreign Guaranty” shall mean a Corporate Guaranty provided by an Affiliate of a Participant that is domiciled in a foreign country, and meets all of the provisions of Tariff, Attachment Q.

**Form 715 Planning Criteria:**

“Form 715 Planning Criteria” shall have the same meaning provided in the Operating Agreement.

**Forward Daily Natural Gas Prices:**

“Forward Daily Natural Gas Prices” shall have the meaning provided in Tariff, Attachment DD, section 5.10(a)(v-1)(E).

**Forward Hourly Ancillary Services Prices:**

“Forward Hourly Ancillary Services Prices” shall have the meaning provided in Tariff, Attachment DD, section 5.10(a)(v-1)(D).

**Forward Hourly LMPs:**

“Forward Hourly LMPs” shall have the meaning provided in Tariff, Attachment DD, section 5.10(a)(v-1)(C).

**FTR Credit Limit:**

“FTR Credit Limit” shall mean the amount of credit established with PJMSettlement that an FTR Participant has specifically designated to be used for FTR activity in a specific customer account. Any such credit so set aside shall not be considered available to satisfy any other credit requirement the FTR Participant may have with PJMSettlement.

**FTR Credit Requirement:**

“FTR Credit Requirement” shall mean the amount of credit that a Participant must provide in order to support the FTR positions that it holds and/or for which it is bidding. The FTR Credit Requirement shall not include months for which the invoicing has already been completed, provided that PJMSettlement shall have up to two Business Days following the date of the invoice completion to make such adjustments in its credit systems. FTR Credit Requirements are calculated and applied separately for each separate customer account.

**FTR Flow Undiversified:**

“FTR Flow Undiversified” shall have the meaning established in Tariff, Attachment Q, section VI.C.6.

**FTR Historical Value:**

For each FTR for each month, “FTR Historical Value” shall mean the weighted average of historical values over three years for the FTR path using the following weightings: 50% - most recent year; 30% - second year; 20% - third year.

**FTR Holder:**

“FTR Holder” shall mean the PJM Member that has acquired and possesses an FTR.

**FTR Monthly Credit Requirement Contribution:**

For each FTR, for each month, “FTR Monthly Credit Requirement Contribution” shall mean the total FTR cost for the month, prorated on a daily basis, less the FTR Historical Value for the month. For cleared FTRs, this contribution may be negative; prior to clearing, FTRs with negative contribution shall be deemed to have zero contribution.

**FTR Net Activity:**

“FTR Net Activity” shall mean the aggregate net value of the billing line items for auction revenue rights credits, FTR auction charges, FTR auction credits, and FTR congestion credits, and shall also include day-ahead and balancing/real-time congestion charges up to a maximum net value of the sum of the foregoing auction revenue rights credits, FTR auction charges, FTR auction credits and FTR congestion credits.

**FTR Participant:**



“FTR Participant” shall mean any Market Participant that provides or is required to provide Collateral in order to participate in PJM’s FTR market.

**FTR Portfolio Auction Value:**

“FTR Portfolio Auction Value” shall mean for each customer account of a Market Participant, the sum, calculated on a monthly basis, across all FTRs, of the FTR price times the FTR volume in MW.

**Fuel Cost Policy:**

“Fuel Cost Policy” shall mean the document provided by a Market Seller to PJM and the Market Monitoring Unit in accordance with PJM Manual 15 and Operating Agreement, Schedule 2, which documents the Market Seller’s method used to price fuel for calculation of the Market Seller’s cost-based offers for a generation resource.

**Full Notice to Proceed:**

“Full Notice to Proceed” shall mean that all material third party contractors have been given the notice to proceed with construction by the Capacity Market Seller or its agent, with a guaranteed completion date backed by liquidated damages.

## Definitions – L – M – N

### **Legacy Policy:**

“Legacy Policy” shall mean any legislative, executive, or regulatory action that specifically directs a payment outside of PJM Markets to a designated or prospective Generation Capacity Resource and the enactment of such action predates October 1, 2021, regardless of when any implementing governmental action to effectuate the action to direct payment outside of PJM Markets occurs.

### **Limited Demand Resource:**

“Limited Demand Resource” shall have the meaning specified in the Reliability Assurance Agreement.

### **Limited Demand Resource Reliability Target:**

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

not be called (based on the applicable operating reserve margin for the PJM Region and for the relevant LDAs) for more than six hours over any one or more of the tested peak days. Second, PJM adopts the lowest result from these three tests as the Limited Demand Resource Reliability Target. The Limited Demand Resource Reliability Target shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the DR Factor] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

**Limited Resource Constraint:**

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

**Limited Resource Price Decrement:**

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

**List of Approved Contractors:**

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

**Load Interest:**

“Load Interest” shall mean, for the purposes of the minimum offer price rule, responsibility for serving load within the PJM Region, whether by the Capacity Market Seller, an affiliate of the Capacity Market Seller, or by an entity with which the Capacity Market Seller is in contractual privity with respect to the subject Generation Capacity Resource.

**Load Management:**

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

**Load Management Event:**

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

**Load Ratio Share:**

“Load Ratio Share” shall mean the ratio of a Transmission Customer’s Network Load to the Transmission Provider’s total load.

**Load Reduction Event:**

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

**Load Serving Charging Energy:**

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

**Load Serving Entity (LSE):**

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

**Load Shedding:**

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

**Local Upgrades:**

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

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

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

**Location:**

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

**LOC Deviation:**

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

**Locational Deliverability Area (LDA):**

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

**Locational Deliverability Area Reliability Requirement:**

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

**Locational Price Adder:**

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

**Locational Reliability Charge:**

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

**Locational UCAP:**

“Locational UCAP” shall mean unforced capacity that a Member with available uncommitted capacity sells in a bilateral transaction to a Member that previously committed capacity through an RPM Auction but now requires replacement capacity to fulfill its RPM Auction commitment. The Locational UCAP Seller retains responsibility for performance of the resource providing such replacement capacity.

**Locational UCAP Seller:**

“Locational UCAP Seller” shall mean a Member that sells Locational UCAP.

**Long-lead Project:**

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

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

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

**Loss Price:**

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

**M2M Flowgate:**

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

**Maintenance Adder:**

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

**Manual Load Dump Action:**

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

**Manual Load Dump Warning:**

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

**Marginal Value:**

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

**Market Monitor:**

“Market Monitor” means the head of the Market Monitoring Unit.

**Market Monitoring Unit or MMU:**

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

**Market Monitoring Unit Advisory Committee or MMU Advisory Committee:**

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

**Market Operations Center:**

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

**Market Participant:**

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

**Market Participant Energy Injection:**

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

**Market Participant Energy Withdrawal:**

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

**Market Seller Offer Cap:**

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

**Market Violation:**

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

**Material Modification:**

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

**Maximum Daily Starts:**



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

**Maximum Emergency:**

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

**Maximum Facility Output:**

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

**Maximum Generation Emergency:**

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

**Maximum Generation Emergency Alert:**

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

**Maximum Run Time:**

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

**Maximum Weekly Starts:**

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

**Member:**

“Member” shall have the meaning provided in the Operating Agreement.

**Merchant A.C. Transmission Facilities:**

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

**Merchant D.C. Transmission Facilities:**

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

**Merchant Network Upgrades:**

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

**Merchant Transmission Facilities:**

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

**Merchant Transmission Provider:**

“Merchant Transmission Provider” shall mean an Interconnection Customer that (1) owns, controls, or controls the rights to use the transmission capability of, Merchant D.C. Transmission Facilities and/or Controllable A.C. Merchant Transmission Facilities that connect the Transmission System with another control area, (2) has elected to receive Transmission Injection Rights and Transmission Withdrawal Rights associated with such facility pursuant to Tariff, Part IV, section 36, and (3) makes (or will make) the transmission capability of such facilities

available for use by third parties under terms and conditions approved by the Commission and stated in the Tariff, consistent with Tariff, section 38.

**Metering Equipment:**

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

**Minimum Annual Resource Requirement:**

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

**Minimum Down Time:**

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

**Minimum Extended Summer Resource Requirement:**

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

**Minimum Generation Emergency:**

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

**Minimum Participation Requirements:**

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

**Minimum Run Time:**

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

**MISO:**

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

**MOPR Floor Offer Price:**

“MOPR Floor Offer Price” shall mean a minimum offer price applicable to certain Market Seller’s Capacity Resources under certain conditions, as determined in accordance with Tariff, Attachment DD, sections 5.14(h), ~~and 5.14(h-1)~~, and 5.14(h-2).

**Multi-Driver Project:**

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

**Native Load Customers:**

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

**NERC:**

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

**NERC Interchange Distribution Calculator:**

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

**Net Benefits Test:**

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

**Net Cost of New Entry:**

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

**Net Obligation:**

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

**Net Sell Position:**

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

**Network Customer:**

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

**Network External Designated Transmission Service:**

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

**Network Integration Transmission Service:**

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

**Network Load:**

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

**Network Operating Agreement:**

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

**Network Operating Committee:**

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

**Network Resource:**

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

**Network Service User:**

“Network Service User” shall mean an entity using Network Transmission Service.

**Network Transmission Service:**

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

**Network Upgrades:**

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

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

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

**Neutral Party:**

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

**New Entry Capacity Resource with State Subsidy:**

“New Entry Capacity Resource with State Subsidy” shall mean (1) starting with the 2022/2023 Delivery Year, the MWs (in installed capacity) comprising a Capacity Resource with State Subsidy that have not cleared in an RPM Auction pursuant to its Sell Offer at or above its resource-specific MOPR Floor Offer Price or the applicable default New Entry MOPR Floor Offer Price or (2) starting with the Base Residual Auction for the 2022/2023 Delivery Year, any of those MWs (in installed capacity) comprising a Capacity Resource with State Subsidy that was not included in an FRR Capacity Plan at the time of the Base Residual Auction or the subject of a Sell Offer in a Base Residual Auction occurring for a Delivery Year after it last cleared an RPM Auction and since then has yet to clear an RPM Auction pursuant to its Sell

Offer at or above its resource-specific MOPR Floor Offer Price or the applicable default New Entry MOPR Floor Offer Price. Notwithstanding the foregoing, any Capacity Resource that previously cleared an RPM Auction before it became entitled to receive a State Subsidy shall not be deemed a New Entry Capacity Resource, unless, starting with the Base Residual Auction for the 2022/2023 Delivery Year, the Capacity Resource with State Subsidy was not the subject of a Sell Offer in a Base Residual Auction or included in an FRR Capacity Plan at the time of the Base Residual Auction for a Delivery Year after it last cleared an RPM Auction.

**New PJM Zone(s):**

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

**New Service Customers:**

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

**New Service Request:**

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

**New Services Queue:**

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

**New York ISO or NYISO:**

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

**Nodal Reference Price:**

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



**No-load Cost:**

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

**Nominal Rated Capability:**

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

**Nominated Demand Resource Value:**

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

**Nominated Energy Efficiency Value:**

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

**Non-Dispatched Charging Energy:**

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

**Non-Firm Point-To-Point Transmission Service:**

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

**Non-Firm Sale:**

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

**Non-Firm Transmission Withdrawal Rights:**

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

**Non-Performance Charge:**

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

**Nonincumbent Developer:**

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

**Non-Regulatory Opportunity Cost:**

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

**Non-Retail Behind The Meter Generation:**

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

**Non-Synchronized Reserve:**

“Non-Synchronized Reserve” shall mean the reserve capability of non-emergency generation resources that can be converted fully into energy within ten minutes of a request from the Office

of the Interconnection dispatcher, and is provided by equipment that is not electrically synchronized to the Transmission System.

**Non-Synchronized Reserve Event:**

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

**Non-Variable Loads:**

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

**Non-Zone Network Load:**

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

**Normal Maximum Generation:**

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

**Normal Minimum Generation:**

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

## **Definitions – R - S**

### **Ramping Capability:**

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

### **Real-time Congestion Price:**

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

### **Real-time Loss Price:**

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

### **Real-time Energy Market:**

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

### **Real-time Offer:**

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

### **Real-time Prices:**

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

### **Real-time Settlement Interval:**

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

### **Real-time System Energy Price:**

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

### **Reasonable Efforts:**

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

**Receiving Party:**

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

**Referral:**

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

**Reference Resource:**

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

**Regional Entity:**

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

**Regional Transmission Expansion Plan:**

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

**Regional Transmission Group (RTG):**

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

**Regulation:**

“Regulation” shall mean the capability of a specific generation resource or Demand Resource with appropriate telecommunications, control and response capability to separately increase and

decrease its output or adjust load in response to a regulating control signal, in accordance with the specifications in the PJM Manuals.

**Regulation Zone:**

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

**Relevant Electric Retail Regulatory Authority:**

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

**Reliability Assurance Agreement or PJM Reliability Assurance Agreement:**

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

**Reliability Pricing Model Auction:**

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

**Required Transmission Enhancements:**

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

**Reserved Capacity:**

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

**Reserve Penalty Factor:**

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

**Reserve Sub-zone:**

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

**Reserve Zone:**

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

**Residual Auction Revenue Rights:**

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

**Residual Metered Load:**

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

**Resource Substitution Charge:**

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

**Revenue Data for Settlements:**

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

**RPM Seller Credit:**

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

**Scheduled Incremental Auctions:**

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

**Schedule of Work:**

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

**Scope of Work:**

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

**Seasonal Capacity Performance Resource:**

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

**Secondary Systems:**

“Secondary Systems” shall mean control or power circuits that operate below 600 volts, AC or DC, including, but not limited to, any hardware, control or protective devices, cables, conductors,



electric raceways, secondary equipment panels, transducers, batteries, chargers, and voltage and current transformers.

**Second Incremental Auction:**

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

**Security:**

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

**Segment:**

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

**Self-Supply:**

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

**Self-Supply Entity:**

“Self-Supply Entity” shall mean the following types of Load Serving Entity that operate under long-standing business models: single customer entity, public power entity, or vertically integrated utility, where “vertically integrated utility” means a utility that owns generation, includes such generation in its regulated rates, and earns a regulated return on its investment in such generation or receives any cost recovery for such generation through bilateral contracts; “single customer entity” means a Load Serving Entity that serves at retail only customers that are under common control with such Load Serving Entity, where such control means holding 51% or more of the voting securities or voting interests of the Load Serving Entity and all its retail customers; and “public power entity” means cooperative and municipal utilities, including public power supply entities comprised of either or both of the same and rural electric cooperatives, and joint action agencies.

**Self-Supply Seller:**

“Self-Supply Seller” shall mean, for purposes of evaluating Buyer-Side Market Power, the following types of Load Serving Entities that operate under long-standing business models: vertically integrated utility or public power entity, where “vertically integrated utility” means a utility that owns generation, includes such generation in its state-regulated rates, and earns a state-regulated return on its investment in such generation; and “public power entity” means electric cooperatives that are either rate regulated by the state or have their long-term resource plan approved or otherwise reviewed and accepted by a Relevant Electric Retail Regulatory Authority and municipal utilities or joint action agencies that are subject to direct regulation by a Relevant Electric Retail Regulatory Authority.

**Sell Offer:**

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

**Service Agreement:**

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

**Service Commencement Date:**

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

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

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

**Short-term Project:**

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

**Short-Term Resource Procurement Target:**

“Short-Term Resource Procurement Target” shall mean, for Delivery Years through May 31, 2018, as to the PJM Region, for purposes of the Base Residual Auction, 2.5% of the PJM Region Reliability Requirement determined for such Base Residual Auction, for purposes of the First Incremental Auction, 2% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction; and, for purposes of the Second Incremental Auction, 1.5% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual

Auction; and, as to any Zone, an allocation of the PJM Region Short-Term Resource Procurement Target based on the Preliminary Zonal Forecast Peak Load, reduced by the amount of load served under the FRR Alternative. For any LDA, the LDA Short-Term Resource Procurement Target shall be the sum of the Short-Term Resource Procurement Targets of all Zones in the LDA.

**Short-Term Resource Procurement Target Applicable Share:**

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

**Site:**

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

**Small Commercial Customer:**

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

**Small Generation Resource:**

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

**Small Inverter Facility:**

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

**Small Inverter ISA:**

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

**Special Member:**

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

**Spot Market Backup:**

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

**Spot Market Energy:**

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

**Start Additional Labor Costs:**

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

**Start-Up Costs:**

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

**State:**

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

**State Commission:**

“State Commission” shall mean any state regulatory agency having jurisdiction over retail electricity sales in any State in the PJM Region.

**State Estimator:**

“State Estimator” shall mean the computer model of power flows specified in Operating Agreement, Schedule 1, section 2.3 and the parallel provisions of Tariff, Attachment K-Appendix, section 2.3.

**State Subsidy:**

“State Subsidy” shall mean a direct or indirect payment, concession, rebate, subsidy, non-bypassable consumer charge, or other financial benefit that is as a result of any action, mandated process, or sponsored process of a state government, a political subdivision or agency of a state, or an electric cooperative formed pursuant to state law, and that

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

Notwithstanding the foregoing, State Subsidy shall not include (a) payments, concessions, rebates, subsidies, or incentives designed to incent, or participation in a program, contract or other arrangement that utilizes criteria designed to incent or promote, general industrial development in an area or designed to incent siting facilities in that county or locality rather than another county or locality; (b) state action that imposes a tax or assesses a charge utilizing the parameters of a regional program on a given set of resources notwithstanding the tax or cost having indirect benefits on resources not subject to the tax or cost (e.g., Regional Greenhouse Gas Initiative); (c) any indirect benefits to a Capacity Resource as a result of any transmission project approved as part of the Regional Transmission Expansion Plan; (d) any contract, legally enforceable obligation, or rate pursuant to the Public Utility Regulatory Policies Act or any other state-administered federal regulatory program (e.g., the Cross-State Air Pollution Rule); (e) any revenues from the sale or allocation, either direct or indirect, to an Entity Providing Supply Services to Default Retail Service Provider where such entity’s obligations was awarded through a state default procurement auction that was subject to independent oversight by a consultant or manager who certifies that the auction was conducted through a non-discriminatory and competitive bidding process, subject to the below condition, and provided further that nothing herein would exempt a Capacity Resource that would otherwise be subject to the minimum offer price rule pursuant to this Tariff; (f) any revenues for providing capacity as part of an FRR Capacity Plan or through bilateral transactions with FRR Entities; or (g) any voluntary and arm’s length bilateral transaction (including but not limited to those reported pursuant to Tariff, Attachment DD, section 4.6), such as a power purchase agreement or other similar contract where the buyer is a Self-Supply Entity and the transaction is (1) a short term transaction (one-year or less) or (2) a long-term transaction that is the result of a competitive process that was not fuel-specific and is not used for the purpose of supporting uneconomic construction,

development, or operation of the subject Capacity Resource, provided however that if the Self-Supply Entity is responsible for offering the Capacity Resource into an RPM Auction, the specified amount of installed capacity purchased by such Self-Supply Entity shall be considered to receive a State Subsidy in the same manner, under the same conditions, and to the same extent as any other Capacity Resource of a Self-Supply Entity. For purposes of subsection (e) of this definition, a state default procurement auction that has been certified to be a result of a non-discriminatory and competitive bidding process shall:

- (i) have no conditions based on the ownership (except supplier diversity requirements or limits), location (except to meet PJM deliverability requirements), affiliation, fuel type, technology, or emissions of any resources or supply (except state-mandated renewable portfolio standards for which Capacity Resources are separately subject to the minimum offer price rule or eligible for an exemption);
- (ii) result in contracts between an Entity Providing Supply Services to Default Retail Service Provider and the electric distribution company for a retail default generation supply product and none of those contracts require that the retail obligation be sourced from any specific Capacity Resource or resource type as set forth in subsection (i) above; and
- (iii) establish market-based compensation for a retail default generation supply product that retail customers can avoid paying for by obtaining supply from a competitive retail supplier of their choice.

**State of Charge:**

“State of Charge” shall mean the quantity of physical energy stored in an Energy Storage Resource Model Participant in proportion to its maximum State of Charge capability. State of Charge is quantified as defined in the PJM Manuals.

**State of Charge Management:**

“State of Charge Management” shall mean the control of State of Charge of an Energy Storage Resource Market Participant using minimum and maximum charge and discharge limits, changes in operating mode, charging and discharging offer curves, and self-scheduling of non-dispatchable purchases and sales of energy in the PJM markets. State of Charge Management shall not interfere with an Energy Storage Resource Model Participant’s obligation to follow PJM dispatch, consistent with all other resources.

**Station Power:**

“Station Power” shall mean energy used for operating the electric equipment on the site of a generation facility located in the PJM Region or for the heating, lighting, air-conditioning and office equipment needs of buildings on the site of such a generation facility that are used in the operation, maintenance, or repair of the facility. Station Power does not include any energy (i) used to power synchronous condensers; (ii) used for pumping at a pumped storage facility; (iii) used in association with restoration or black start service; or (iv) that is Direct Charging Energy.

**Sub-Annual Resource Constraint:**

“Sub-Annual Resource Constraint” shall mean, for the 2017/2018 Delivery Year and for FRR Capacity Plans the 2017/2018 and 2018/2019 Delivery Years, for the PJM Region or for each LDA for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for a Delivery Year, a limit on the total amount of Unforced Capacity that can be committed as Limited Demand Resources and Extended Summer Demand Resources for the 2017/2018 Delivery Year in the PJM Region or in such LDA, calculated as the Sub-Annual Resource Reliability Target for the PJM Region or for such LDA, respectively, minus the Short-Term Resource Procurement Target for the PJM Region or for such LDA, respectively.

**Sub-Annual Resource Price Decrement:**

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

**Sub-Annual Resource Reliability Target:**

“Sub-Annual Reliability Target” for the PJM Region or an LDA, shall mean the maximum amount of the combination of Extended Summer Demand Resources and Limited Demand Resources in Unforced Capacity determined by PJM to be consistent with the maintenance of reliability, stated in Unforced Capacity, that shall be used to calculate the Minimum Annual Resource Requirement for Delivery Years through May 31, 2017 and the Sub-Annual Resource Constraint for the 2017/2018 and 2018/2019 Delivery Years. As more fully set forth in the PJM Manuals, PJM calculates the Sub-Annual Resource Reliability Target, by first determining a reference annual loss of load expectation (“LOLE”) assuming no Demand Resources. The calculation for the unconstrained portion of the PJM Region uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast and iteratively shifting the load distributions to result in the Installed Reserve Margin established for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). The calculation for each relevant LDA uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Capacity Emergency Transfer Objective study for the Delivery Year in question). For the relevant LDA calculation, the weekly capacity distributions are adjusted to reflect the Capacity Emergency Transfer Limit for the Delivery Year in question.

For both the PJM Region and LDA analyses, PJM then models the commitment of varying amounts of DR (displacing otherwise committed generation) as interruptible from May 1 through October 31 and unavailable from November 1 through April 30 and calculates the LOLE at each DR level. The Extended Summer DR Reliability Target is the DR amount, stated as a percentage of the unrestricted peak load, that produces no more than a ten percent increase in the LOLE,

compared to the reference value. The Sub-Annual Resource Reliability Target shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the DR Factor] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

**Sub-meter:**

“Sub-meter” shall mean a metering point for electricity consumption that does not include all electricity consumption for the end-use customer as defined by the electric distribution company account number. PJM shall only accept sub-meter load data from end-use customers for measurement and verification of Regulation service as set forth in the Economic Load Response rules and PJM Manuals.

**Summer-Period Capacity Performance Resource:**

“Summer-Period Capacity Performance Resource” shall have the same meaning specified in Tariff, Attachment DD, section 5.5A.

**Surplus Interconnection Customer:**

“Surplus Interconnection Customer” shall mean either an Interconnection Customer whose Generating Facility is already interconnected to the PJM Transmission System or one of its affiliates, or an unaffiliated entity that submits a Surplus Interconnection Request to utilize Surplus Interconnection Service within the Transmission System in the PJM Region. A Surplus Interconnection Customer is not a New Service Customer.

**Surplus Interconnection Request:**

“Surplus Interconnection Request” shall mean a request submitted by a Surplus Interconnection Customer, pursuant to Tariff, Attachment RR, to utilize Surplus Interconnection Service within the Transmission System in the PJM Region. A Surplus Interconnection Request is not a New Service Request.

**Surplus Interconnection Service:**

“Surplus Interconnection Service” shall mean any unneeded portion of Interconnection Service established in an Interconnection Service Agreement, such that if Surplus Interconnection Service is utilized, the total amount of Interconnection Service at the Point of Interconnection would remain the same.

**Switching and Tagging Rules:**

“Switching and Tagging Rules” shall mean the switching and tagging procedures of Interconnected Transmission Owners and Interconnection Customer as they may be amended from time to time.



**Synchronized Reserve:**

“Synchronized Reserve” shall mean the reserve capability of generation resources that can be converted fully into energy or Demand Resources whose demand can be reduced within ten minutes from the request of the Office of the Interconnection dispatcher, and is provided by equipment that is electrically synchronized to the Transmission System.

**Synchronized Reserve Event:**

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

**Synchronized Reserve Requirement:**

“Synchronized Reserve Requirement” shall mean the megawatts required to be maintained in a Reserve Zone or Reserve Sub-zone as Synchronized Reserve, absent any increase to account for additional reserves scheduled to address operational uncertainty. The Synchronized Reserve Requirement is calculated in accordance with the PJM Manuals.

**System Condition:**

“System Condition” shall mean a specified condition on the Transmission Provider’s system or on a neighboring system, such as a constrained transmission element or flowgate, that may trigger Curtailment of Long-Term Firm Point-to-Point Transmission Service using the curtailment priority pursuant to Tariff, Part II, section 13.6. Such conditions must be identified in the Transmission Customer’s Service Agreement.

**System Energy Price:**

“System Energy Price” shall mean the energy component of the Locational Marginal Price, which is the price at which the Market Seller has offered to supply an additional increment of energy from a resource, calculated as specified in Operating Agreement, Schedule 1, section 2 and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

**System Impact Study:**

“System Impact Study” shall mean an assessment by the Transmission Provider of (i) the adequacy of the Transmission System to accommodate a Completed Application, an Interconnection Request or an Upgrade Request, (ii) whether any additional costs may be incurred in order to provide such transmission service or to accommodate an Interconnection Request, and (iii) with respect to an Interconnection Request, an estimated date that an Interconnection Customer’s Customer Facility can be interconnected with the Transmission System and an estimate of the

Interconnection Customer's cost responsibility for the interconnection; and (iv) with respect to an Upgrade Request, the estimated cost of the requested system upgrades or expansion, or of the cost of the system upgrades or expansion, necessary to provide the requested incremental rights.

**System Protection Facilities:**

“System Protection Facilities” shall refer to the equipment required to protect (i) the Transmission System, other delivery systems and/or other generating systems connected to the Transmission System from faults or other electrical disturbance occurring at or on the Customer Facility, and (ii) the Customer Facility from faults or other electrical system disturbance occurring on the Transmission System or on other delivery systems and/or other generating systems to which the Transmission System is directly or indirectly connected. System Protection Facilities shall include such protective and regulating devices as are identified in the Applicable Technical Requirements and Standards or that are required by Applicable Laws and Regulations or other Applicable Standards, or as are otherwise necessary to protect personnel and equipment and to minimize deleterious effects to the Transmission System arising from the Customer Facility.

## 5.14 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) an adjustment, if required, to account for Resource Make-Whole Payments; and (5) an adjustment, if required to provide sufficient revenue for payment of any PRD Credits, all as determined in accordance with the optimization algorithm.

ii) The Office of the Interconnection shall calculate and post the Adjusted Zonal Capacity Price following each Incremental Auction. The Adjusted Zonal Capacity Price for each Zone shall equal the sum of: (1) the average marginal value of system capacity weighted by the Unforced Capacity cleared in all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); (2) the average Locational Price Adder weighted by the Unforced Capacity cleared in all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); (3) an adjustment, if required, to account for adders paid to Annual Resources and Extended Summer Demand Resources for all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); (4) an adjustment, if required, to account for Resource Make-Whole Payments for all actions previously conducted (excluding any Resource Make-Whole Payments to be charged to the buyers of replacement capacity); and (5) an adjustment, if required to provide sufficient revenue for payment of any PRD Credits. The Adjusted Zonal Capacity Price may decrease if Unforced Capacity is decommitted or the Resource Clearing Price decreases in an Incremental Auction.

iii) The Office of the Interconnection shall calculate and post the Final Zonal Capacity Price for each Delivery Year after the final auction is held for such Delivery Year, as set forth above. The Final Zonal Capacity Price for each Zone shall equal the Adjusted Zonal Capacity Price, as further adjusted to reflect any decreases in the Nominated Demand Resource Value of any existing Demand Resource cleared in the Base Residual Auction and Second Incremental Auction.

g) Resource Substitution Charge

Each Capacity Market Buyer in an Incremental Auction securing replacement capacity shall pay a Resource Substitution Charge equal to the Capacity Resource Clearing Price resulting from such auction multiplied by the megawatt quantity of Unforced Capacity purchased by such Market Buyer in such auction.

h) Minimum Offer Price Rule for Certain New Generation Capacity Resources that are not Capacity Resources with State Subsidy for 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) ~~Beginning with the Delivery Year that begins on June 1, 2019,~~  
 ¶ The gross Cost of New Entry component of the Net Asset Class Cost of New Entry shall be adjusted to reflect changes in generating plant construction costs in the same manner as set forth for the cost of new entry in 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 2021/2022 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)(A), provided that the energy revenue estimate for each CONE Area shall be based on the Zone within such CONE Area that has the highest energy revenue estimate calculated under the methodology in that subsection. The net energy and ancillary services revenue estimate for a combined cycle generator shall be determined in the same manner as that prescribed for a combustion turbine generator in the previous sentence, except that the heat rate assumed for the combined cycle resource shall be 6.722 MMBtu/Mwh, the variable operations and maintenance expenses for such resource shall be \$3.23 per MWh, the Peak Hour Dispatch scenario for both the Day Ahead and Real Time Energy Markets shall be modified to dispatch the CC resource continuously during the full peak-hour period, as described in Peak Hour Dispatch, for each such period that the resource is economic (using the test set forth in such definition), rather than only during the four-hour blocks within such period that such resource is economic, and the ancillary service revenues shall be \$3198 per MW-year.~~

For the 2022/2023 Delivery Year ~~and subsequent Delivery Years~~, 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 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 2021/2022 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, energy demand, emissions allowance prices, and expected environmental or energy policies that affect the seller’s forecast of electricity prices in such region, employing input data from sources readily available to the public. Documentation for net revenues also may include, as available and applicable, plant performance and capability information, including heat rate, start-up times and costs, forced outage rates, planned outage schedules, maintenance cycle, fuel costs and other variable operations and maintenance expenses, and ancillary service capabilities. In addition to the documentation identified herein and in the PJM Manuals, the Capacity Market Seller shall provide any additional supporting~~

~~information reasonably requested by the Office of the Interconnection or the Market Monitoring Unit to evaluate the Sell Offer. Requests for additional documentation will not extend the deadline by which the Office of the Interconnection or the Market Monitoring Unit must provide their determinations of the Minimum Offer Price Rule exception request.~~

For the 2022/2023 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 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, aAny 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 ~~and all subsequent Delivery Years~~, each Capacity Market Seller must certify to the Office of Interconnection, in accordance with the PJM Manuals, whether or not each Capacity Resource (other than Demand Resource and Energy Efficiency Resource) that the

Capacity Market Seller intends to offer into the RPM Auction qualifies as a Capacity Resource with a State Subsidy (including by way of Jointly Owned Cross-Subsidized Capacity Resource) and identify (with specificity) any State Subsidy. Capacity Market Sellers that intend to offer a Demand Resource or an Energy Efficiency Resource into the RPM Auction shall certify to the Office of Interconnection, in accordance with the PJM Manuals, whether or not such Demand Resource or Energy Efficiency Resource qualifies as a Capacity Resource with a State Subsidy no later than thirty (30) days prior to the commencement of the offer period of any RPM Auction conducted for the 2022/2023 Delivery Year ~~and all subsequent Delivery Years~~. All Capacity Market Sellers shall be responsible for each certification irrespective of any guidance developed by the Office of the Interconnection and the Market Monitoring Unit. A Capacity Resource shall be deemed a Capacity Resource with State Subsidy if the Capacity Market Seller fails to timely certify whether or not a Capacity Resource is entitled to a State Subsidy unless the Capacity Market Seller receives a waiver from the Commission. 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 ~~and all subsequent Delivery Years~~, 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 ~~and all subsequent Delivery Years~~. 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, ~~as adjusted for Delivery Years subsequent to the 2022/2023 Delivery Year~~, net of estimated net energy and ancillary service revenues for the resource type and Zone in which the resource is located.

<b>Resource Type</b>	<b>Gross Cost of New Entry (2022/2023 \$/ MW-day) (Nameplate)</b>
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.

~~Commencing with the Base Residual Auction for the 2023/2024 Delivery Year, the Office of the Interconnection shall adjust the default gross costs of new entry in the table above and for load-backed Demand Resources, and post the preliminary estimates of the adjusted applicable default New Entry MOPR Floor Offer Prices on its website, by no later than one hundred fifty (150) days prior to the commencement of the offer period for each Base Residual Auction.~~ To determine the adjusted applicable default New Entry MOPR Floor Offer Prices for all resource types except for load-backed Demand Resources and Energy Efficiency Resources, the Office of the Interconnection shall adjust the gross costs of new entry utilizing, for combustion turbine and combined cycle resource types, the same Applicable BLS Composite Index applied for such Delivery Year to adjust the CONE value used to determine the Variable Resource Requirement Curve, in accordance with Tariff, Attachment DD, section 5.10(a)(iv), and for all other resource types, the “BLS Producer Price Index Turbines and Turbine Generator Sets” component of the

Applicable BLS Composite Index used to determine the Variable Resource Requirement Curve shall be replaced with the “BLS Producer Price Index Final Demand, Goods Less Food & Energy, Private Capital Equipment” when adjusting the gross costs of new entry. The resultant value shall then be then adjusted further by a factor of 1.022 for nuclear, coal, combustion turbine, 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.

~~Beginning with the Delivery Year that commences June 1, 2022, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall review the default gross cost of new entry values. Such review may include, without limitation, analyses of the fixed development, construction, operation, and maintenance costs for such resource types. Based on the results of such review, PJM shall propose either to modify or retain the default gross cost of new entry values stated in the table above and the default gross cost of new entry value for Energy Efficiency Resources. The Office of the Interconnection shall post publicly and solicit stakeholder comment regarding the proposal. If, as a result of this process, changes to the default gross cost of new entry values are proposed, the Office of the Interconnection shall file such proposed modifications with the FERC by October 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.~~

New Entry Capacity 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, ~~as adjusted for Delivery Years subsequent for the 2022/2023 Delivery Year 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 subsection (ii) below.

<b>Existing Resource Type</b>	<b>Default Gross ACR (2022/2023 (\$/MW-day) (Nameplate)</b>
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.

~~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 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 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 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) ~~(i)~~—The Capacity Market Seller shall not receive a State Subsidy for any part of the relevant Delivery Year in which it elects a competitive exemption or certifies that it is not a Capacity Resource with State Subsidy. ~~In furtherance of this prohibition, if a Capacity Resource that (1) is a New Entry Capacity Resource with State Subsidy that elects the competitive exemption in subsection (4)(A) above and clears an RPM Auction for a given Delivery Year, but prior to the end of the asset life that PJM used to set the applicable default New Entry MOPR Floor Price in the RPM Auction that the New Entry Capacity Resource with State Subsidy first cleared, elects to accept a State Subsidy or (2) is not a Capacity Resource with State Subsidy at the time of the RPM Auction for the Delivery Year for which it first cleared an RPM Auction but prior to the end of the asset life that PJM used to set the applicable default New Entry MOPR Floor Price in the RPM Auction that the Capacity Resource first cleared, receives a State Subsidy, or (3) in the case of Demand Resource, is an end-use customer location MW that receives a State Subsidy and is included in a Demand Resource Registration pursuant to RAA, Schedule 6 to satisfy a Demand Resource commitment that was not designated as a Capacity Resource with State Subsidy at the time it cleared the relevant RPM Auction, then the Capacity Market Seller of that Capacity Resource or end-use customer location MW shall not receive RPM revenues for such resource or end-use customer location MW for any part of that Delivery Year and may not participate in any RPM Auction with such resource or end-use customer location MW, or be eligible to use such resource or end-use customer location MW as replacement capacity starting June 1 of the Delivery Year after the Capacity Market Seller or end-use customer location MW first receives the State Subsidy and continuing for the remainder of the asset life that PJM used to set the applicable default New Entry MOPR Floor Price in the RPM Auction that the Capacity Resource first cleared (20 years, except for battery energy storage, for which such participation restriction shall apply for a period of 15 years). A Jointly Owned Cross-Subsidized Capacity Resource that meets the requirements of either of the two preceding subsections (B)(i)(1) or (2), shall not receive RPM revenues for any part of that Delivery Year and may not participate in any RPM Auction or be eligible to be used as replacement capacity starting June 1 of the Delivery Year and continuing for the number of years specified above, after any joint Capacity Market Seller of the underlying facility first receives the State Subsidy. A Capacity Resource with State Subsidy that is the subject of a bilateral transaction that meets the requirements of either of the two preceding subsections (B)(i)(1) or (2) shall not receive RPM revenues for any part of that Delivery Year and may not participate in any RPM Auction or be eligible to be used as replacement capacity starting June 1 of the Delivery Year and continuing for the number of years specified above if any owner or Capacity Market Seller of the facility receives a State Subsidy. The Capacity Market Seller(s) of any such Capacity Resource or Jointly Owned Cross-Subsidized Capacity Resource shall also return to the Office of the Interconnection any revenues paid to such Capacity Resource associated with their capacity commitment for such Delivery Year and shall retain their RPM commitment and associated obligations for such Delivery Year and for any future Delivery Years in which the resource has already secured a capacity commitment, including any Non-Performance Charges relating to the capacity and remain eligible to collect Performance Payments under this Tariff, Attachment DD, section 10A for the relevant Delivery Year and any subsequent Delivery Years for which it already received an RPM commitment. Notwithstanding the foregoing, Capacity~~

~~Resources that lose their eligibility to participate in RPM pursuant to this section remain eligible for commitment in an FRR Capacity Plan.~~

~~(ii) — If any Capacity Resource that has previously cleared an RPM Auction (1) is a Cleared Capacity Resource with State Subsidy that claims the competitive exemption pursuant to subsection (4)(A) above in an RPM Auction and clears such RPM Auction or (2) was not a Capacity Resource with State Subsidy at the time it cleared an RPM Auction for a given Delivery Year but later becomes entitled to receive a State Subsidy for that Delivery Year, and the Capacity Market Seller subsequently elects to accept a State Subsidy for any part of that Delivery Year, or (3) in the case of Demand Resource, is an end-use customer location that receives a State Subsidy and is included in a Demand Resource Registration pursuant to RAA, Schedule 6 to satisfy a Demand Resource commitment that was not designated as a Capacity Resource with State Subsidy at the time it cleared the relevant RPM Auction, then the Capacity Market Seller of that Capacity Resource or end-use customer location may not receive RPM revenues for such resource or end-use customer location for any part of that Delivery Year, unless it can demonstrate that it would have cleared in the relevant RPM Auction under an offer consistent with the resource-specific exception process outlined above in subsection 5.14(h-1)(3). All Capacity Market Sellers of a Jointly Owned Cross-Subsidized Capacity Resource that meets the requirements of either of the two preceding subsections (B)(ii)(1) or (2) may not receive RPM revenues for any part of that Delivery Year if any joint Capacity Market Seller of the underlying facility accepts a subsidy for that Delivery Year, unless the Capacity Market Seller can demonstrate that the facility would have cleared in the relevant RPM Auction under an offer consistent with the resource-specific exception process outlined above in subsection 5.14(h-1)(3). A Capacity Resource with State Subsidy that is the subject of a bilateral transaction may not receive RPM revenues for any part of that Delivery Year if any owner or Capacity Market Seller of the underlying facility receives a State Subsidy for that Delivery Year, unless the Capacity Market Seller can demonstrate that the facility would have cleared in the relevant RPM Auction under an offer consistent with the resource-specific exception process outlined above in subsection 5.14(h-1)(3), if any owner or Capacity Market Seller of the facility receives a State Subsidy. The Capacity Market Seller(s) of any such Capacity Resources or Jointly Owned Cross-Subsidized Capacity Resource shall return to the Office of the Interconnection any revenues paid to such Capacity Resource associated with their capacity commitment for such Delivery Year and shall retain their RPM commitment and associated obligations for the relevant Delivery Year and remain eligible to collect Performance Payments or to pay Non-Performance Charges, as applicable, pursuant to Tariff, Attachment DD, section 10A.~~

~~(iii) — Any revenues returned to the Office of the Interconnection pursuant to the preceding subsections (i) and (ii) shall be allocated across all load in the RTO that has not selected the FRR Alternative. Such revenues shall be distributed on a pro-rata basis to such LSEs that were charged a Locational Reliability Charge based on their Daily Unforced Capacity Obligations.~~

(5) Self-Supply Entity exemption. A Capacity Resource that 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

2019; or

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

(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 Delivery Year, net of estimated net energy and ancillary service revenues for the resource type and Zone in which the resource is located.

<u>Resource Type</u>	<u>Gross Cost of New Entry (2022/2023 \$/ MW-day) (Nameplate)</u>
<u>Nuclear</u>	<u>\$2,000</u>
<u>Coal</u>	<u>\$1,068</u>
<u>Combined Cycle</u>	<u>\$320</u>
<u>Combustion Turbine</u>	<u>\$294</u>
<u>Fixed Solar PV</u>	<u>\$271</u>
<u>Tracking Solar PV</u>	<u>\$290</u>
<u>Onshore Wind</u>	<u>\$420</u>
<u>Offshore Wind</u>	<u>\$1,155</u>
<u>Battery Energy Storage</u>	<u>\$532</u>

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. 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; and

(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.

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 Delivery Year 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 subsection (ii) below.

<u>Existing Resource Type</u>	<u>Default Gross ACR (2022/2023) (\$/MW-day) (Nameplate)</u>
<u>Nuclear - single</u>	<u>\$697</u>
<u>Nuclear - dual</u>	<u>\$445</u>
<u>Coal</u>	<u>\$80</u>
<u>Combined Cycle</u>	<u>\$56</u>
<u>Combustion Turbine</u>	<u>\$50</u>
<u>Solar PV (fixed and tracking)</u>	<u>\$40</u>
<u>Wind Onshore</u>	<u>\$83</u>

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) 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)(3)(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 Generation Capacity Resource that has previously cleared an RPM Auction for any Delivery Year and where such Sell Offer is 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 unit-specific MOPR Floor Offer Price for such Capacity Resource pursuant to Tariff, Attachment DD, section 5.14(h-2)(4) 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. 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 unit-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) 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 unit-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.

(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

$(\text{Export Path Import} * \text{Export Reserved Capacity}) /$

$(\text{Export Reserved Capacity} + \text{Daily Unforced Capacity Obligations of all LSEs in such Zone}).$

Where:

“Export Path Import” means the megawatts of Unforced Capacity imported into the export interface Zone from the Zone in which the resource designated for export is located.

If more than one Zone forms the interface with such Control Area, then the amount of Export Reserved Capacity shall be apportioned among such Zones for purposes of the above calculation in the same manner as set forth in subsection (i)(1) above.

### (3) Distribution of Revenues

Any revenues collected from the Capacity Export Charge with respect to any capacity export for a Delivery Year, less the credit provided in subsection (i)(2) for such Delivery Year, shall be distributed to the Load Serving Entities in the export-interface Zone that were assessed a

Locational Reliability Charge for such Delivery Year, pro rata based on the Daily Unforced Capacity Obligations of such Load-serving Entities in such Zone during such Delivery Year. If more than one Zone forms the interface with such Control Area, then the revenues shall be apportioned among such Zones for purposes of the above calculation in the same manner as set forth in subsection (i)(1) above.

### **5.14A [Reserved.]**

### **5.14B Generating Unit Capability Verification Test Requirements Transition Provision for RPM Delivery Years 2014/2015, 2015/2016, and 2016/2017**

A. This transition provision applies only with respect to Generation Capacity Resources with existing capacity commitments for the 2014/2015, 2015/2016, or 2016/2017 Delivery Years that experience reductions in verified installed capacity available for sale as a direct result of revised generating unit capability verification test procedures effective with the summer 2014 capability tests, as set forth in the PJM Manuals. A Generation Capacity Resource meeting the description of the preceding sentence, and the Capacity Market Seller of such a resource, are hereafter in this section 5.14B referred to as an “Affected Resource” and an “Affected Resource Owner,” respectively.

B. For each of its Affected Resources, an Affected Resource Owner is required to provide documentation to the Office of the Interconnection sufficient to show a reduction in installed capacity value as a direct result of the revised capability test procedures. Upon acceptance by the

Office of the Interconnection, the Affected Resource's installed capacity value will be updated in the eRPM system to reflect the reduction, and the Affected Resource's Capacity Interconnection Rights value will be updated to reflect the reduction, effective June 1, 2014. The reduction's impact on the Affected Resource's existing capacity commitments for the 2014/2015 Delivery Year will be determined in Unforced Capacity terms, using the final EFORD value established by the Office of the Interconnection for the 2014/2015 Delivery Year as applied to the Third Incremental Auction for the 2014/2015 Delivery Year, to convert installed capacity to Unforced Capacity. The reduction's impact on the Affected Resource's existing capacity commitments for each of the 2015/2016 and 2016/2017 Delivery Years will be determined in Unforced Capacity terms, using the EFORD value from each Sell Offer in each applicable RPM Auction, applied on a pro-rata basis, to convert installed capacity to Unforced Capacity. The Unforced Capacity impact for each Delivery Year represents the Affected Resource's capacity commitment shortfall, resulting wholly and directly from the revised capability test procedures, for which the Affected Resource Owner is subject to a Capacity Resource Deficiency Charge for the Delivery Year, as described in Tariff, Attachment DD, section 8, unless the Affected Resource Owner (i) provides replacement Unforced Capacity, as described in Tariff, Attachment DD, section 8.1, prior to the start of the Delivery Year to resolve the Affected Resource's total capacity commitment shortfall; or (ii) requests relief from Capacity Resource Deficiency Charges that result wholly and directly from the revised capability test procedures by electing the transition mechanism described in this section 5.14B ("Transition Mechanism").

C. Under the Transition Mechanism, an Affected Resource Owner may elect to have the Unforced Capacity commitments for all of its Affected Resources reduced for the 2014/2015, 2015/2016, or 2016/2017 Delivery Years to eliminate the capacity commitment shortfalls, across all of its Affected Resources, that result wholly and directly from the revised capability test procedures, and for which the Affected Resource Owner otherwise would be subject to Capacity Resource Deficiency Charges for the Delivery Year. In electing this option, the Affected Resource Owner relinquishes RPM Auction Credits associated with the reductions in Unforced Capacity commitments for all of its Affected Resources for the Delivery Year, and Locational Reliability Charges as described in Tariff, Attachment DD, section 5.14(e) of this Attachment DD are adjusted accordingly. Affected Resource Owners wishing to elect the Transition Mechanism for the 2015/2016 Delivery Year must notify the Office of the Interconnection by May 30, 2014. Affected Resource Owners wishing to elect the Transition Mechanism for the 2016/2017 Delivery Year must notify the Office of the Interconnection by July 25, 2014.

D. The Office of the Interconnection will offset the total reduction (across all Affected Resources and Affected Resource Owners) in Unforced Capacity commitments associated with the Transition Mechanism for the 2015/2016 and 2016/2017 Delivery Years by applying corresponding adjustments to the quantity of Buy Bid or Sell Offer activity in the upcoming Incremental Auctions for each of those Delivery Years, as described in Tariff, Attachment DD, sections 5.12(b)(ii) and 5.12(b)(iii).

E. By electing the Transition Mechanism, an Affected Resource Owner may receive relief from applicable Capacity Resource Deficiency Charges for the 2014/2015, 2015/2016, or 2016/2017 Delivery Years, and a Locational UCAP Seller that sells Locational UCAP based on an Affected Resource owned by the Affected Resource Owner may receive relief from applicable Capacity Resource Deficiency Charges for the 2014/2015 Delivery Year, to the extent that the

Affected Resource Owner demonstrates, to the satisfaction of the Office of the Interconnection, that an inability to deliver the amount of Unforced Capacity previously committed for the 2014/2015, 2015/2016, or 2016/2017 Delivery Years is due to a reduction in verified installed capacity available for sale as a direct result of revised generating unit capability verification test procedures effective with the summer 2014 capability tests, as set forth in the PJM Manuals; provided, however, that the Affected Resource Owner must provide the Office of the Interconnection with all information deemed necessary by the Office of the Interconnection to assess the merits of the request for relief.

#### **5.14C Demand Response Operational Resource Flexibility Transition Provision for RPM Delivery Years 2015/2016 and 2016/2017**

A. This transition provision applies only to Demand Resources for which a Curtailment Service Provider has existing RPM commitments for the 2015/2016 or 2016/2017 Delivery Years (alternatively referred to in this section 5.14C as “Applicable Delivery Years” and each an “Applicable Delivery Year”) that (i) cannot satisfy the 30-minute notification requirement as described in Tariff, Attachment DD-1, section A.2 and the parallel provision of RAA, Schedule 6; (ii) are not excepted from the 30-minute notification requirement as described in Tariff, Attachment DD-1, section A.2 and the parallel provision of RAA, Schedule 6; and (iii) cleared in the Base Residual Auction or First Incremental Auction for the 2015/2016 Delivery Year, or cleared in the Base Residual Auction for the 2016/2017 Delivery Year. A Demand Resource meeting these criteria and the Curtailment Service Provider of such a resource are hereafter in this section 5.14C referred to as an “Affected Demand Resource” and an “Affected Curtailment Service Provider,” respectively.

B. For this section 5.14C to apply to an Affected Demand Resource, the Affected Curtailment Service Provider must notify the Office of the Interconnection in writing, with regard to the following information by the applicable deadline:

- i) For each applicable Affected Demand Resource: the number of cleared megawatts of Unforced Capacity for the Applicable Delivery Year by end-use customer site that the Affected Curtailment Service Provider cannot deliver, calculated based on the most current information available to the Affected Curtailment Service Provider; the end-use customer name; electric distribution company’s account number for the end-use customer; address of end-use customer; type of Demand Resource (i.e., Limited DR, Annual DR, Extended Summer DR); the Zone or sub-Zone in which the end-use customer is located; and, a detailed description of why the end-use customer cannot comply with the 30-minute notification requirement or qualify for one of the exceptions to the 30-minute notification requirement provided in Tariff, Attachment DD-1 section A.2 and the parallel provision of RAA, Schedule 6.
- ii) If applicable, a detailed analysis that quantifies the amount of cleared megawatts of Unforced Capacity for the Applicable Delivery Year for prospective customer sales that could not be contracted by the Affected Curtailment Service Provider because of the 30-minute notification requirement provided in Tariff, Attachment DD-1, section A.2 and the parallel provisions of RAA, Schedule 6 that the Affected Curtailment Service



Provider cannot deliver, by type of Demand Resource (i.e. Limited DR, Annual DR, Extended Summer DR) and by Zone and sub-Zone, as applicable. The analysis should include the amount of Unforced Capacity expected from prospective customer sales for each Applicable Delivery Year and must include supporting detail to substantiate the difference in reduced sales expectations. The Affected Curtailment Service Provider should maintain records to support its analysis.

1. For the 2015/2016 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the Third Incremental Auction for the 2015/2016 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision may not sell or offer to sell megawatts in the modeled LDA or sub-LDA where an Affected Demand Resource is located in the Third Incremental Auction for the 2015/2016 Delivery Year.

2. For the 2016/2017 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the Second Incremental Auction for the 2016/2017 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision may not sell or offer to sell megawatts in the modeled LDA or sub-LDA where an Affected Demand Resource is located in the Second or Third Incremental Auctions for the 2016/2017 Delivery Year.

3. For the 2016/2017 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the Third Incremental Auction for the 2016/2017 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision must not have sold or offered to sell megawatts in the modeled LDA or sub-LDA where an Affected Demand Resource is located in the Second Incremental Auction for the 2016/2017 Delivery Year, and may not sell or offer to sell megawatts in the modeled LDA or sub-LDA where an Affected Demand Resource is located in the Third Incremental Auction for the 2016/2017 Delivery Year.

C. For the Third Incremental Auction for the 2015/2016 Delivery Year and the First, Second, and Third Incremental Auctions for the 2016/2017 Delivery Year, the Office of the Interconnection shall publish aggregate information on the undeliverable megawatts declared under this transition provision (hereafter, “non-viable megawatts”), by type of Demand Resource and by Zone or sub-Zone, concurrently with its posting of planning parameters for the applicable Scheduled Incremental Auction. Non-viable megawatts for a Scheduled Incremental Auction for an Applicable Delivery Year represent those megawatts meeting the criteria of subsection A above and declared in accordance with subsection B above. Prior to each Third Incremental Auction for an Applicable Delivery Year, the Office of the Interconnection shall apply adjustments equal to the declared non-viable megawatt quantity to the quantity of Buy Bid or Sell Offer activity in the upcoming Scheduled Incremental Auctions for the Applicable Delivery Year, as described in Tariff, Attachment DD, sections 5.12(b)(ii) and 5.12(b)(iii). Prior to the Second Incremental Auction for the 2016/2017 Delivery Year, the Office of the Interconnection shall adjust the recalculated PJM Region Reliability Requirement and recalculated LDA Reliability Requirements, as described in Tariff, Attachment DD, section 5.4(c), by the applicable quantity of declared non-viable megawatts, and shall update the PJM Region Reliability Requirement and each LDA Reliability Requirement for such Second Incremental

Auction only if the combined change of the applicable adjustment and applicable recalculation is greater than or equal to the lesser of (i) 500 megawatts or (ii) one percent of the prior PJM Region Reliability Requirement or one percent of the prior LDA Reliability Requirement, as applicable.

D. Prior to the start of each Applicable Delivery Year, the Office of the Interconnection shall reduce, by type of Demand Resource and by Zone or sub-Zone, the capacity commitment of each Affected Curtailment Service Provider that utilizes this transition provision for the Applicable Delivery Year based on the non-viable megawatts declared by the Affected Curtailment Service Provider under this transition provision. If the Affected Curtailment Service Provider cleared megawatts from multiple Affected Demand Resources of the same type and Zone or sub-Zone, or cleared megawatts in multiple RPM Auctions for the Applicable Delivery Year, the Office of the Interconnection shall allocate the reduction in capacity commitment by type of Demand Resource and by Zone or sub-Zone across the applicable Affected Demand Resources and relevant RPM Auctions. Such allocation shall be performed on a pro-rata basis, based on megawatts cleared by the Affected Demand Resources in the relevant RPM Auctions.

E. For each Applicable Delivery Year, an Affected Curtailment Service Provider that utilizes this transition provision for the Applicable Delivery Year relinquishes an Affected Demand Resource's RPM Auction Credits for the amount of capacity commitment reduction as determined under subsection D above. Locational Reliability Charges as described in Tariff, Attachment DD, section 5.14(e) are also adjusted accordingly.

#### **5.14D Capacity Performance and Base Capacity Transition Provision for RPM Delivery Years 2016/2017 and 2017/2018**

A. This transition provision applies only for procuring Capacity Performance Resources for the 2016/2017 and 2017/2018 Delivery Years.

B. For both the 2016/2017 and 2017/2018 Delivery Years, PJM will hold a Capacity Performance Transition Incremental Auction to procure Capacity Performance Resources.

1. For each Capacity Performance Transition Incremental Auction, the optimization algorithm shall consider:

- the target quantities of Capacity Performance Resources specified below;
- the Sell Offers submitted in such auction.

The Office of the Interconnection shall submit a Buy Bid based on the quantity of Capacity Performance Resources specified for that Delivery Year. For the 2016/2017 Delivery Year, the Office of the Interconnection shall submit a Buy Bid, at a price no higher than 0.5 times the Net CONE value for the PJM Region determined for the Base Residual Auction for that Delivery Year, for a quantity of Capacity Performance Resources equal to 60 percent of the updated Reliability Requirement for the PJM Region. For the 2017/2018 Delivery Year, the Office of the Interconnection shall submit a Buy Bid, at a price no higher than 0.6 times the Net CONE value for the PJM Region determined for the Base Residual Auction for that Delivery Year, for a quantity

of Capacity Performance Resources equal to 70 percent of the updated Reliability Requirement for the PJM Region.

2. For each Capacity Performance Transition Incremental Auction, the Office of the Interconnection shall calculate a clearing price to be paid for each megawatt-day of Unforced Capacity that clears in such auction. For the 2016/2017 Delivery Year, the Capacity Resource Clearing Price for any Capacity Performance Transition Incremental Auction shall not exceed 0.5 times the Net CONE value for the PJM Region determined for the Base Residual Auction for that Delivery Year. For the 2017/2018 Delivery Year, the Capacity Resource Clearing Price for any Capacity Performance Transition Incremental Auction shall not exceed 0.6 times the Net CONE value for the PJM Region determined for the Base Residual Auction for that Delivery Year.

3. A Capacity Market Seller may offer any Capacity Resource that has not been committed in an FRR Capacity Plan, that qualifies as a Capacity Performance Resource under Tariff, Attachment DD, section 5.5A(a) and that (i) has not cleared an RPM Auction for that Delivery Year; or (ii) has cleared in an RPM Auction for that Delivery Year. A Capacity Market Seller may offer an external Generation Capacity Resource to the extent that such resource: (i) is reasonably expected, by the relevant Delivery Year, to meet all applicable requirements to be treated as equivalent to PJM Region internal generation that is not subject to NERC tagging as an interchange transaction; (ii) has long-term firm transmission service confirmed on the complete transmission path from such resource into PJM; and (iii) is, by written commitment of the Capacity Market Seller, subject to the same obligations imposed on Generation Capacity Resources located in the PJM Region by Tariff, Attachment DD, section 6.6 to offer their capacity into RPM Auctions.

4. Capacity Resources that already cleared an RPM Auction for a Delivery Year, retain the capacity obligations for that Delivery Year, and clear in a Capacity Performance Transition Incremental Auction for the same Delivery Year shall: (i) receive a payment equal to the Capacity Resource Clearing Price as established in that Capacity Performance Transition Incremental Auction; and (ii) not be eligible to receive a payment for clearing in any prior RPM Auction for that Delivery Year.

D. All Capacity Performance Resources that clear in a Capacity Performance Transition Incremental Auction will be subject to the Non-Performance Charge set forth in Tariff, Attachment DD, section 10A.

#### **5.14E Demand Response Legacy Direct Load Control Transition Provision for RPM Delivery Years 2016/2017, 2017/2018, and 2018/2019**

A. This transition provision applies only to Demand Resources for which a Curtailment Service Provider has existing RPM commitments for the 2016/2017, 2017/2018, or 2018/2019 Delivery Years (alternatively referred to in this section 5.14E as “Applicable Delivery Years” and each an “Applicable Delivery Year”) that (i) qualified as Legacy Direct Load Control before June 1, 2016 as described in Tariff, Attachment DD-1, section G and the parallel provision of RAA, Schedule 6; (ii) cannot meet the requirements for using statistical sampling for residential non-interval metered customers as described in Tariff, Attachment DD-1, section K and the parallel provision of RAA, Schedule 6; and (iii) cleared in the Base Residual Auction or First

Incremental Auction for the 2016/2017 Delivery Year, cleared in the Base Residual Auction for the 2017/2018 Delivery Year, or cleared in the Base Residual Auction for the 2018/2019 Delivery Year. A Demand Resource meeting these criteria and the Curtailment Service Provider of such a resource are hereafter in this section 5.14E referred to as an “Affected Demand Resource” and an “Affected Curtailment Service Provider,” respectively.

B. For this section 5.14E to apply to an Affected Demand Resource, the Affected Curtailment Service Provider must notify the Office of the Interconnection in writing, with regard to the following information, by the applicable deadline:

- i) For each applicable Affected Demand Resource: the number of cleared megawatts of Unforced Capacity for the Applicable Delivery Year by end-use customer site that the Affected Curtailment Service Provider cannot deliver, calculated based on the most current information available to the Affected Curtailment Service Provider; electric distribution company’s account number for the end-use customer; address of end-use customer; type of Demand Resource (i.e., Limited DR, Annual DR, Extended Summer DR); the Zone or sub-Zone in which the end-use customer is located; and, a detailed description of why the end-use customer cannot comply with statistical sampling for residential non-interval metered customers requirement as described in Tariff, Attachment DD-1, section K and the parallel provision of RAA, Schedule 6.
- ii) If applicable, a detailed analysis that quantifies the amount of cleared megawatts of Unforced Capacity for the Applicable Delivery Year for prospective customer sales that could not be contracted by the Affected Curtailment Service Provider because of the statistical sampling for residential non-interval metered customers requirement as described in Tariff, Attachment DD-1, section K and the parallel provision of RAA, Schedule 6 that the Affected Curtailment Service Provider cannot deliver, by type of Demand Resource (i.e. Limited DR, Annual DR, Extended Summer DR) and by Zone and sub-Zone, as applicable. The analysis should include the amount of Unforced Capacity expected from prospective customer sales for each Applicable Delivery Year and must include supporting detail to substantiate the difference in reduced sales expectations. The Affected Curtailment Service Provider should maintain records to support its analysis.

1. For the 2016/2017 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the Second and/or Third Incremental Auction for the 2016/2017 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision may not sell or offer to sell megawatts in the matching LDA or sub-LDA where an Affected Demand Resource is located in the Second or Third Incremental Auction for the 2016/2017 Delivery Year.

2. For the 2017/2018 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the First, Second and/or Third Incremental Auction for the 2017/2018 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision may not sell or offer

to sell megawatts in the matching LDA or sub-LDA where an Affected Demand Resource is located in the First, Second or Third Incremental Auctions for the 2017/2018 Delivery Year.

3. For the 2018/2019 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the First, Second and/or Third Incremental Auction for the 2018/2019 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision may not sell or offer to sell megawatts in the matching LDA or sub-LDA where an Affected Demand Resource is located in the First, Second or Third Incremental Auctions for the 2018/2019 Delivery Year.

C. For the Second and Third Incremental Auction for the 2016/2017 Delivery Year, the First, Second, and Third Incremental Auctions for the 2017/2018 Delivery Year, and the First, Second, and Third Incremental Auctions for the 2018/2019 Delivery Year, the Office of the Interconnection shall publish aggregate information on the undeliverable megawatts declared under this transition provision (hereafter, “non-viable megawatts”), by type of Demand Resource and by Zone or sub-Zone, concurrently with its posting of planning parameters for the applicable Scheduled Incremental Auction. Non-viable megawatts for a Scheduled Incremental Auction for an Applicable Delivery Year represent those megawatts meeting the criteria of subsection A above and declared in accordance with subsection B above. Prior to each Scheduled Incremental Auction for an Applicable Delivery Year, the Office of the Interconnection shall apply adjustments equal to the declared non-viable megawatt quantity to the quantity of Buy Bid or Sell Offer activity in the upcoming Scheduled Incremental Auctions for the Applicable Delivery Year, as described in Tariff, Attachment DD, sections 5.12(b)(ii) and 5.12(b)(iii). Prior to the Second Incremental Auction for the 2016/2017 Delivery Year, the First and Second Incremental Auction for the 2017/2018 Delivery Year, and the First and Second Incremental Auction for the 2018/2019 Delivery Year, the Office of the Interconnection shall adjust the recalculated PJM Region Reliability Requirement and recalculated LDA Reliability Requirements, as described in Tariff, Attachment DD, section 5.4(c), by the applicable quantity of declared non-viable megawatts, and shall update the PJM Region Reliability Requirement and each LDA Reliability Requirement for such Incremental Auction only if the combined change of the applicable adjustment and applicable recalculation is greater than or equal to the lesser of (i) 500 megawatts or (ii) one percent of the prior PJM Region Reliability Requirement or one percent of the prior LDA Reliability Requirement, as applicable.

D. Prior to the start of each Applicable Delivery Year, the Office of the Interconnection shall reduce, by type of Demand Resource and by Zone or sub-Zone, the capacity commitment of each Affected Curtailment Service Provider that utilizes this transition provision for the Applicable Delivery Year based on the non-viable megawatts declared by the Affected Curtailment Service Provider under this transition provision. If the Affected Curtailment Service Provider cleared megawatts from multiple Affected Demand Resources of the same type and Zone or sub-Zone, or cleared MWs in multiple RPM Auctions for the Applicable Delivery Year, the Office of the Interconnection shall allocate the reduction in capacity commitment by type of Demand Resource and by Zone or sub-Zone across the applicable Affected Demand Resources and relevant RPM Auctions. Such allocation shall be performed on a pro-rata basis, based on megawatts cleared by the Affected Demand Resources in the relevant RPM Auctions.

E. For each Applicable Delivery Year, an Affected Curtailment Service Provider that

utilizes this transition provision for the Applicable Delivery Year relinquishes an Affected Demand Resource's RPM Auction credits for the amount of capacity commitment reduction as determined under subsection D above. Locational Reliability Charges as described in Tariff, Attachment DD, section 5.14(e) are also adjusted accordingly.

**ATTACHMENT DD-3**

State policies or programs accepted as Conditioned State Support and subject to the Minimum Offer Price Rule, specified in Tariff, Attachment DD, section 5.14(h-2), are as follows:

[reserved]

# Attachment B

Revisions to the  
PJM Open Access Transmission Tariff

(Clean Format)



## **Definitions – A - B**

### **Abnormal Condition:**

“Abnormal Condition” shall mean any condition on the Interconnection Facilities which, determined in accordance with Good Utility Practice, is: (i) outside normal operating parameters such that facilities are operating outside their normal ratings or that reasonable operating limits have been exceeded; and (ii) could reasonably be expected to materially and adversely affect the safe and reliable operation of the Interconnection Facilities; but which, in any case, could reasonably be expected to result in an Emergency Condition. Any condition or situation that results from lack of sufficient generating capacity to meet load requirements or that results solely from economic conditions shall not, standing alone, constitute an Abnormal Condition.

### **Acceleration Request:**

“Acceleration Request” shall mean a request pursuant to Operating Agreement, Schedule 1, section 1.9.4A, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.9.4A, to accelerate or reschedule a transmission outage scheduled pursuant to Operating Agreement, Schedule 1, section 1.9.2 or Operating Agreement, Schedule 1, section 1.9.4, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.9.2 or Tariff, Attachment K-Appendix, section 1.9.4.

### **Additional Day-ahead Scheduling Reserves Requirement:**

“Additional Day-ahead Scheduling Reserves Requirement” shall mean the portion of the Day-ahead Scheduling Reserves Requirement that is required in addition to the Base Day-ahead Scheduling Reserves Requirement to ensure adequate resources are procured to meet real-time load and operational needs, as specified in the PJM Manuals.

### **Affected System:**

“Affected System” shall mean an electric system other than the Transmission Provider’s Transmission System that may be affected by a proposed interconnection or on which a proposed interconnection or addition of facilities or upgrades may require modifications or upgrades to the Transmission System.

### **Affected System Operator:**

“Affected System Operator” shall mean an entity that operates an Affected System or, if the Affected System is under the operational control of an independent system operator or a regional transmission organization, such independent entity.

### **Affiliate:**

“Affiliate” shall mean any two or more entities, one of which Controls the other or that are under common Control. “Control,” as that term is used in this definition, shall mean the possession, directly or indirectly, of the power to direct the management or policies of an entity. Ownership

of publicly-traded equity securities of another entity shall not result in Control or affiliation for purposes of the Tariff or Operating Agreement if the securities are held as an investment, the holder owns (in its name or via intermediaries) less than 10 percent (10%) of the outstanding securities of the entity, the holder does not have representation on the entity's board of directors (or equivalent managing entity) or vice versa, and the holder does not in fact exercise influence over day-to-day management decisions. Unless the contrary is demonstrated to the satisfaction of the Members Committee, Control shall be presumed to arise from the ownership of or the power to vote, directly or indirectly, ten percent or more of the voting securities of such entity.

**Agreements:**

“Agreements” shall mean the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C., the PJM Open Access Transmission Tariff, the Reliability Assurance Agreement, and/or other agreements between PJM Interconnection, L.L.C. and its Members.

**Ancillary Services:**

“Ancillary Services” shall mean those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider's Transmission System in accordance with Good Utility Practice.

**Annual Demand Resource:**

“Annual Demand Resource” shall have the meaning specified in the Reliability Assurance Agreement.

**Annual Energy Efficiency Resource:**

“Annual Energy Efficiency Resource” shall have the meaning specified in the Reliability Assurance Agreement.

**Annual Resource:**

“Annual Resource” shall mean a Generation Capacity Resource, an Annual Energy Efficiency Resource or an Annual Demand Resource.

**Annual Resource Price Adder:**

“Annual Resource Price Adder” shall mean, for Delivery Years starting June 1, 2014 and ending May 31, 2017, an addition to the marginal value of Unforced Capacity and the Extended Summer Resource Price Adder as necessary to reflect the price of Annual Resources required to meet the applicable Minimum Annual Resource Requirement.

**Annual Revenue Rate:**

“Annual Revenue Rate” shall mean the rate employed to assess a compliance penalty charge on a

Curtailed Service Provider under Tariff, Attachment DD, section 11.

**Annual Transmission Costs:**

“Annual Transmission Costs” shall mean the total annual cost of the Transmission System for purposes of Network Integration Transmission Service shall be the amount specified in Attachment H for each Zone until amended by the applicable Transmission Owner or modified by the Commission.

**Applicable Laws and Regulations:**

“Applicable Laws and Regulations” shall mean all duly promulgated applicable federal, State and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority having jurisdiction over the relevant parties, their respective facilities, and/or the respective services they provide.

**Applicable Regional Entity:**

“Applicable Regional Entity” shall mean the Regional Entity for the region in which a Network Customer, Transmission Customer, New Service Customer, or Transmission Owner operates.

**Applicable Standards:**

“Applicable Standards” shall mean the requirements and guidelines of NERC, the Applicable Regional Entity, and the Control Area in which the Customer Facility is electrically located; the PJM Manuals; and Applicable Technical Requirements and Standards.

**Applicable Technical Requirements and Standards:**

“Applicable Technical Requirements and Standards” shall mean those certain technical requirements and standards applicable to interconnections of generation and/or transmission facilities with the facilities of an Interconnected Transmission Owner or, as the case may be and to the extent applicable, of an Electric Distributor, as published by Transmission Provider in a PJM Manual provided, however, that, with respect to any generation facilities with maximum generating capacity of 2 MW or less (synchronous) or 5 MW or less (inverter-based) for which the Interconnection Customer executes a Construction Service Agreement or Interconnection Service Agreement on or after March 19, 2005, “Applicable Technical Requirements and Standards” shall refer to the “PJM Small Generator Interconnection Applicable Technical Requirements and Standards.” All Applicable Technical Requirements and Standards shall be publicly available through postings on Transmission Provider’s internet website.

**Applicant:**

“Applicant” shall mean an entity desiring to become a PJM Member, become a Market Participant, engage in market activities, or to take Transmission Service that has submitted the

PJMSettlement credit application, PJMSettlement credit agreement and other required submittals as set forth in Tariff, Attachment Q.

**Application:**

“Application” shall mean a request by an Eligible Customer for transmission service pursuant to the provisions of the Tariff.

**Attachment Facilities:**

“Attachment Facilities” shall mean the facilities necessary to physically connect a Customer Facility to the Transmission System or interconnected distribution facilities.

**Attachment H:**

“Attachment H” shall refer collectively to the Attachments to the PJM Tariff with the prefix “H” that set forth, among other things, the Annual Transmission Rates for Network Integration Transmission Service in the PJM Zones.

**Auction Revenue Rights:**

“Auction Revenue Rights” or “ARRs” shall mean the right to receive the revenue from the Financial Transmission Right auction, as further described in Operating Agreement, Schedule 1, section 7.4, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.

**Auction Revenue Rights Credits:**

“Auction Revenue Rights Credits” shall mean the allocated share of total FTR auction revenues or costs credited to each holder of Auction Revenue Rights, calculated and allocated as specified in Operating Agreement, Schedule 1, section 7.4.3, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.3.

**Authorized Government Agency:**

“Authorized Government Agency” means a regulatory body or government agency, with jurisdiction over PJM, the PJM Market, or any entity doing business in the PJM Market, including, but not limited to, the Commission, State Commissions, and state and federal attorneys general.

**Avoidable Cost Rate:**

“Avoidable Cost Rate” shall mean a component of the Market Seller Offer Cap calculated in accordance with Tariff, Attachment DD, section 6.

**Balancing Congestion Charges:**

“Balancing Congestion Charges” shall be equal to the sum of congestion charges collected from Market Participants that are purchasing energy in the Real-time Energy Market minus [the sum of congestion charges paid to Market Participants that are selling energy in the Real-time Energy Market plus any congestion charges calculated pursuant to the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38), plus any congestion charges calculated pursuant to the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 45), plus any congestion charges calculated pursuant to agreements between the Office of the Interconnection and other entities, plus any charges or credits calculated pursuant to Operating Agreement, Schedule 1, section 3.8, and the parallel provisions of Tariff, Attachment K-Appendix, section 3.8, as applicable)].

**Balancing Ratio:**

“Balancing Ratio” shall have the meaning provided in Tariff, Attachment DD, section 10A.

**Base Capacity Demand Resource:**

“Base Capacity Demand Resource” shall have the meaning specified in the Reliability Assurance Agreement.

**Base Capacity Demand Resource Constraint:**

“Base Capacity Demand Resource Constraint” for the PJM Region or an LDA, shall mean, for the 2018/2019 and 2019/2020 Delivery Years, the maximum Unforced Capacity amount, determined by PJM, of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources that is consistent with the maintenance of reliability. As more fully set forth in the PJM Manuals, PJM calculates the Base Capacity Demand Resource Constraint for the PJM Region or an LDA, by first determining a reference annual loss of load expectation (“LOLE”) assuming no Base Capacity Resources, including no Base Capacity Demand Resources or Base Capacity Energy Efficiency Resources. The calculation for the PJM Region uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast and iteratively shifting the load distributions to result in the Installed Reserve Margin established for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). The calculation for each relevant LDA uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). For the relevant LDA calculation, the weekly capacity distributions are adjusted to reflect the Capacity Emergency Transfer Limit for the Delivery Year in question.

For both the PJM Region and LDA analyses, PJM then models the commitment of varying amounts of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources (displacing otherwise committed generation) as interruptible from June 1 through September 30

and unavailable the rest of the Delivery Year in question and calculates the LOLE at each DR and EE level. The Base Capacity Demand Resource Constraint is the combined amount of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources, stated as a percentage of the unrestricted annual peak load, that produces no more than a five percent increase in the LOLE, compared to the reference value. The Base Capacity Demand Resource Constraint shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

**Base Capacity Demand Resource Price Decrement:**

“Base Capacity Demand Resource Price Decrement” shall mean, for the 2018/2019 and 2019/2020 Delivery Years, a difference between the clearing price for Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources and the clearing price for Base Capacity Resources and Capacity Performance Resources, representing the cost to procure additional Base Capacity Resources or Capacity Performance Resources out of merit order when the Base Capacity Demand Resource Constraint is binding.

**Base Capacity Energy Efficiency Resource:**

“Base Capacity Energy Efficiency Resource” shall have the meaning specified in the Reliability Assurance Agreement.

**Base Capacity Resource:**

“Base Capacity Resource” shall mean a Capacity Resource as described in Tariff, Attachment DD, section 5.5A(b).

**Base Capacity Resource Constraint:**

“Base Capacity Resource Constraint” for the PJM Region or an LDA, shall mean, for the 2018/2019 and 2019/2020 Delivery Years, the maximum Unforced Capacity amount, determined by PJM, of Base Capacity Resources, including Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources, that is consistent with the maintenance of reliability. As more fully set forth in the PJM Manuals, PJM calculates the above Base Capacity Resource Constraint for the PJM Region or an LDA, by first determining a reference annual loss of load expectation (“LOLE”) assuming no Base Capacity Resources, including no Base Capacity Demand Resources or Base Capacity Energy Efficiency Resources. The calculation for the PJM Region uses the weekly load distribution from the Installed Reserve Margin study for the Delivery Year in question (based on the most recent load forecast and iteratively shifting the load distributions to result in the Installed Reserve Margin established for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). The calculation for each relevant LDA uses a weekly load distribution (based on the Installed Reserve Margin study and the most recent load forecast for the Delivery Year in

question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). For the relevant LDA calculation, the weekly capacity distributions are adjusted to reflect the Capacity Emergency Transfer Limit for the Delivery Year in question. Additionally, for the PJM Region and relevant LDA calculation, the weekly capacity distributions are adjusted to reflect winter ratings.

For both the PJM Region and LDA analyses, PJM models the commitment of an amount of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources equal to the Base Capacity Demand Resource Constraint (displacing otherwise committed generation). PJM then models the commitment of varying amounts of Base Capacity Resources (displacing otherwise committed generation) as unavailable during the peak week of winter and available the rest of the Delivery Year in question and calculates the LOLE at each Base Capacity Resource level. The Base Capacity Resource Constraint is the combined amount of Base Capacity Demand Resources, Base Capacity Energy Efficiency Resources and Base Capacity Resources, stated as a percentage of the unrestricted annual peak load, that produces no more than a ten percent increase in the LOLE, compared to the reference value. The Base Capacity Resource Constraint shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [one minus the pool-wide average EFORD] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

**Base Capacity Resource Price Decrement:**

“Base Capacity Resource Price Decrement” shall mean, for the 2018/2019 and 2019/2020 Delivery Years, a difference between the clearing price for Base Capacity Resources and the clearing price for Capacity Performance Resources, representing the cost to procure additional Capacity Performance Resources out of merit order when the Base Capacity Resource Constraint is binding.

**Base Day-ahead Scheduling Reserves Requirement:**

“Base Day-ahead Scheduling Reserves Requirement” shall mean the thirty-minute reserve requirement for the PJM Region established consistent with the Applicable Standards, plus any additional thirty-minute reserves scheduled in response to an RTO-wide Hot or Cold Weather Alert or other reasons for conservative operations.

**Base Load Generation Resource**

“Base Load Generation Resource” shall mean a Generation Capacity Resource that operates at least 90 percent of the hours that it is available to operate, as determined by the Office of the Interconnection in accordance with the PJM Manuals.

**Base Offer Segment:**

“Base Offer Segment” shall mean a component of a Sell Offer based on an existing Generation

Capacity Resource, equal to the Unforced Capacity of such resource, as determined in accordance with the PJM Manuals. If the Sell Offers of multiple Market Sellers are based on a single Existing Generation Capacity Resource, the Base Offer Segments of such Market Sellers shall be determined pro rata based on their entitlements to Unforced Capacity from such resource.

**Base Residual Auction:**

“Base Residual Auction” shall mean the auction conducted three years prior to the start of the Delivery Year to secure commitments from Capacity Resources as necessary to satisfy any portion of the Unforced Capacity Obligation of the PJM Region not satisfied through Self-Supply.

**Batch Load Demand Resource:**

“Batch Load Demand Resource” shall mean a Demand Resource that has a cyclical production process such that at most times during the process it is consuming energy, but at consistent regular intervals, ordinarily for periods of less than ten minutes, it reduces its consumption of energy for its production processes to minimal or zero megawatts.

**Behind The Meter Generation:**

“Behind The Meter Generation” shall refer to a generation unit that delivers energy to load without using the Transmission System or any distribution facilities (unless the entity that owns or leases the distribution facilities has consented to such use of the distribution facilities and such consent has been demonstrated to the satisfaction of the Office of the Interconnection); provided, however, that Behind The Meter Generation does not include (i) at any time, any portion of such generating unit’s capacity that is designated as a Generation Capacity Resource; or (ii) in an hour, any portion of the output of such generating unit that is sold to another entity for consumption at another electrical location or into the PJM Interchange Energy Market.

**Black Start Service:**

“Black Start Service” shall mean the capability of generating units to start without an outside electrical supply or the demonstrated ability of a generating unit with a high operating factor (subject to Transmission Provider concurrence) to automatically remain operating at reduced levels when disconnected from the grid.

**Border Yearly Charge:**

“Border Yearly Charge” shall mean the yearly charge determined in accordance with Tariff, Schedule 7.

**Breach:**

“Breach” shall mean the failure of a party to perform or observe any material term or condition



of Tariff, Part IV or Tariff, Part VI, or any agreement entered into thereunder as described in the relevant provisions of such agreement.

**Breaching Party:**

“Breaching Party” shall mean a party that is in Breach of Tariff, Part IV or Tariff, Part VI and/or an agreement entered into thereunder.

**Business Day:**

“Business Day” shall mean a day in which the Federal Reserve System is open for business and is not a scheduled PJM holiday.

**Buy Bid:**

“Buy Bid” shall mean a bid to buy Capacity Resources in any Incremental Auction.

**Buyer-Side Market Power:**

“Buyer-Side Market Power” shall mean the ability of Capacity Market Sellers with a Load Interest to suppress RPM Auction clearing prices for the overall benefit of their (and/or affiliates) portfolio of generation and load.

## **Definitions – C-D**

### **Canadian Guaranty:**

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

### **Cancellation Costs:**

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

### **Capacity:**

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

### **Capacity Emergency Transfer Limit:**

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

### **Capacity Emergency Transfer Objective:**

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

### **Capacity Export Transmission Customer:**

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

### **Capacity Import Limit:**

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

### **Capacity Interconnection Rights:**

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

**Capacity Market Buyer:**

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

**Capacity Market Seller:**

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

**Capacity Performance Resource:**

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

**Capacity Performance Transition Incremental Auction:**

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

**Capacity Resource:**

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

**Capacity Resource with State Subsidy:**

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

**Capacity Resource Clearing Price:**

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

**Capacity Storage Resource:**

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

**Capacity Transfer Right:**

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

**Capacity Transmission Injection Rights:**

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

**Charge Economic Maximum Megawatts:**

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

**Charge Economic Minimum Megawatts:**

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

**Charge Mode:**

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

**Charge Ramp Rate:**

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

**Cleared Capacity Resource with State Subsidy:**

“Cleared Capacity Resource with State Subsidy” shall mean a Capacity Resource with State Subsidy that has cleared in an RPM Auction for a Delivery Year that is prior to the 2022/2023 Delivery Year or, starting with 2022/2023 Delivery Year, the MWs (in installed capacity) comprising a Capacity Resource with State Subsidy that have cleared an RPM Auction pursuant to its Sell Offer at or above its resource-specific MOPR Floor Offer Price or the applicable default New Entry MOPR Floor Offer Price and since then, any of those MWs (in installed capacity) comprising a Capacity Resource with State Subsidy have been, the subject of a Sell Offer into the Base Residual Auction or included in an FRR Capacity Plan at the time of the Base Residual Auction for the relevant Delivery Year.

**Cold/Warm/Hot Notification Time:**

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

**Cold/Warm/Hot Start-up Time:**

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

engines or systems, maintaining stable fuel/air ratios, and other auxiliary equipment necessary for startup.

**Cold Weather Alert:**

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

**Collateral:**

“Collateral” shall be a cash deposit, including any interest thereon, or a Letter of Credit issued for the benefit of PJM or PJMSettlement, in an amount and form determined by and acceptable to PJM or PJMSettlement, provided by a Participant to PJM or PJMSettlement as credit support in order to participate in the PJM Markets or take Transmission Service. “Collateral” shall also include surety bonds, except for the purpose of satisfying the FTR Credit Requirement, in which case only a cash deposit or Letter of Credit will be acceptable.

**Collateral Call:**

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

**Commencement Date:**

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

**Committed Offer:**

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

**Completed Application:**

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

**Compliance Aggregation Area (CAA):**

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

**Composite Energy Offer:**

“Composite Energy Offer” for generation resources shall mean the sum (in \$/MWh) of the Incremental Energy Offer and amortized Start-Up Costs and amortized No-load Costs, and for Economic Load Response Participant resources the sum (in \$/MWh) of the Incremental Energy Offer and amortized shutdown costs, as determined in accordance with Tariff, Attachment K-Appendix, section 2.4 and Tariff, Attachment K-Appendix, section 2.4A and the PJM Manuals.

**Conditional Incremental Auction:**

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

**Conditioned State Support:**

“Conditioned State Support” shall mean any financial benefit required or incentivized by a state, or political subdivision of a state acting in its sovereign capacity, that is provided outside of PJM Markets and in exchange for the sale of a FERC-jurisdictional product conditioned on clearing in any RPM Auction, where “conditioned on clearing in any RPM Auction” refers to specific directives as to the level of the offer that must be entered for the relevant Generation Capacity Resource in the RPM Auction or directives that the Generation Capacity Resource is required to clear in any RPM Auction. Conditioned State Support shall not include any Legacy Policy.

**CONE Area:**

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

**Confidential Information:**

“Confidential Information” shall mean any confidential, proprietary, or trade secret information of a plan, specification, pattern, procedure, design, device, list, concept, policy, or compilation relating to the present or planned business of a New Service Customer, Transmission Owner, or other Interconnection Party or Construction Party, which is designated as confidential by the party supplying the information, whether conveyed verbally, electronically, in writing, through

inspection, or otherwise, and shall include, without limitation, all information relating to the producing party's technology, research and development, business affairs and pricing, and any information supplied by any New Service Customer, Transmission Owner, or other Interconnection Party or Construction Party to another such party prior to the execution of an Interconnection Service Agreement or a Construction Service Agreement.

**Congestion Price:**

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

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

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

**Constraint Relaxation Logic:**

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

**Constructing Entity:**

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

**Construction Party:**

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

**Construction Service Agreement:**



“Construction Service Agreement” shall mean either an Interconnection Construction Service Agreement or an Upgrade Construction Service Agreement.

**Contingent Facilities:**

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

**Continuous Mode:**

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

**Control Area:**

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

- (1) match the power output of the generators within the electric power system(s) and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);
- (2) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;
- (3) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and
- (4) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

**Control Zone:**

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

**Controllable A.C. Merchant Transmission Facilities:**

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

**Coordinated External Transaction:**

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

**Coordinated Transaction Scheduling:**

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

**Corporate Guaranty:**

“Corporate Guaranty” shall mean a legal document, in a form acceptable to PJM and/or PJMSettlement, used by a Credit Affiliate of an entity to guaranty the obligations of another entity.

**Cost of New Entry:**

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

**Costs:**

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

**Counterparty:**

“Counterparty” shall mean PJMSettlement as the contracting party, in its name and own right and not as an agent, to an agreement or transaction with a Market Participant or other entities, including the agreements and transactions with customers regarding transmission service and other transactions under the PJM Tariff and the Operating Agreement. PJMSettlement shall not

be a counterparty to (i) any bilateral transactions between Members, or (ii) any Member's self-supply of energy to serve its load, or (iii) any Member's self-schedule of energy reported to the Office of the Interconnection to the extent that energy serves that Member's own load.

**Credit Affiliate:**

"Credit Affiliate" shall mean Principals, corporations, partnerships, firms, joint ventures, associations, joint stock companies, trusts, unincorporated organizations or entities, one of which directly or indirectly controls the other or that are both under common Control. "Control," as that term is used in this definition, shall mean the possession, directly or indirectly, of the power to direct the management or policies of a person or an entity.

**Credit Available for Export Transactions:**

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

**Credit Available for Virtual Transactions:**

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

**Credit Breach:**

"Credit Breach" shall mean (a) the failure of a Participant to perform, observe, meet or comply with any requirements of Tariff, Attachment Q or other provisions of the Agreements, other than a Financial Default, or (b) a determination by PJM and notice to the Participant that a Participant represents an unreasonable credit risk to the PJM Markets; that, in either event, has not been cured or remedied after any required notice has been given and any cure period has elapsed.

**Credit-Limited Offer:**

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

**Credit Support Default:**

"Credit Support Default," shall mean (a) the failure of any Guarantor of a Market Participant to make any payment, or to perform, observe, meet or comply with any provisions of the applicable

Guaranty or Credit Support Document that has not been cured or remedied, after any required notice has been given and an opportunity to cure (if any) has elapsed, (b) a representation made or deemed made by a Guarantor in any Credit Support Document that proves to be false, incorrect or misleading in any material respect when made or deemed made, (c) the failure of a Guaranty or other Credit Support Document to be in full force and effect prior to the satisfaction of all obligations of such Participant to PJM, without PJM's consent, or (d) a Guarantor repudiating, disaffirming, disclaiming or rejecting, in whole or in part, its obligations under the Guaranty or challenging the validity of the Guaranty.

**Credit Support Document:**

“Credit Support Document” shall mean any agreement or instrument in any way guaranteeing or securing any or all of a Participant's obligations under the Agreements (including, without limitation, the provisions of Tariff, Attachment Q), any agreement entered into under, pursuant to, or in connection with the Agreements or any agreement entered into under, pursuant to, or in connection with the Agreements and/or any other agreement to which PJM, PJMSettlement and the Participant are parties, including, without limitation, any Corporate Guaranty, Letter of Credit, or agreement granting PJM and PJMSettlement a security interest.

**CTS Enabled Interface:**

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

**CTS Interface Bid:**

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

**Curtailement:**

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

**Curtailement Service Provider:**

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

**Customer Facility:**

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

**Customer-Funded Upgrade:**

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

**Customer Interconnection Facilities:**

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

**Daily Deficiency Rate:**

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

**Daily Unforced Capacity Obligation:**

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

**Day-ahead Congestion Price:**

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

**Day-ahead Energy Market:**

“Day-ahead Energy Market” shall mean the schedule of commitments for the purchase or sale of energy and payment of Transmission Congestion Charges developed by the Office of the Interconnection as a result of the offers and specifications submitted in accordance with Operating Agreement, Schedule 1, section 1.10 and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.

**Day-ahead Energy Market Injection Congestion Credits:**

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

**Day-ahead Energy Market Transmission Congestion Charges:**

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

**Day-ahead Energy Market Withdrawal Congestion Charges:**

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

**Day-ahead Loss Price:**

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

**Day-ahead Prices:**

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

**Day-Ahead Pseudo-Tie Transaction:**

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

**Day-ahead Scheduling Reserves:**

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

**Day-ahead Scheduling Reserves Market:**

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

**Day-ahead Scheduling Reserves Requirement:**

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

**Day-ahead Scheduling Reserves Resources:**

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

**Day-ahead Settlement Interval:**

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

**Day-ahead System Energy Price:**

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

**Deactivation:**

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

**Deactivation Avoidable Cost Credit:**

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

**Deactivation Avoidable Cost Rate:**

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

**Deactivation Date:**

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

**Decrement Bid:**

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

**Default:**

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

**Delivering Party:**

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

**Delivery Year:**

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

**Demand Bid:**

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



**Demand Bid Limit:**

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

**Demand Bid Screening:**

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

**Demand Resource:**

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

**Demand Resource Factor or DR Factor:**

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

**Designated Agent:**

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

**Designated Entity:**

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

**Direct Assignment Facilities:**

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

**Direct Charging Energy:**

“Direct Charging Energy” shall mean the energy that an Energy Storage Resource purchases from the PJM Interchange Energy Market and (i) later resells to the PJM Interchange Energy Market; or (ii) is lost to conversion inefficiencies, provided that such inefficiencies are an

unavoidable component of the conversion, storage, and discharge process that is used to resell energy back to the PJM Interchange Energy Market.

**Direct Load Control:**

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

**Discharge Economic Maximum Megawatts:**

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

**Discharge Economic Minimum Megawatts:**

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

**Discharge Mode:**

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

**Discharge Ramp Rate:**

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

**Dispatch Rate:**

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

**Dispatched Charging Energy:**

“Dispatched Charging Energy” shall mean Direct Charging Energy that an Energy Storage Resource Model Participant receives from the electric grid pursuant to PJM dispatch while providing one of the following services in the PJM markets: Energy Imbalance Service pursuant

to Tariff, Schedule 4; Regulation; Tier 2 Synchronized Reserves; or Reactive Service. Energy Storage Resource Model Participants shall be considered to be providing Energy Imbalance Service when they are dispatchable by PJM in real-time.

**Dynamic Schedule:**

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

**Dynamic Transfer:**

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

## **Definitions – E - F**

### **Economic-based Enhancement or Expansion:**

“Economic-based Enhancement or Expansion” shall have the same meaning provided in the Operating Agreement.

### **Economic Load Response Participant:**

“Economic Load Response Participant” shall mean a Member or Special Member that qualifies under Operating Agreement, Schedule 1, section 1.5A, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.5A, to participate in the PJM Interchange Energy Market and/or Ancillary Services markets through reductions in demand.

### **Economic Maximum:**

“Economic Maximum” shall mean the highest incremental MW output level, submitted to PJM market systems by a Market Participant, that a unit can achieve while following economic dispatch.

### **Economic Minimum:**

“Economic Minimum” shall mean the lowest incremental MW output level, submitted to PJM market systems by a Market Participant, that a unit can achieve while following economic dispatch.

### **Effective FTR Holder:**

“Effective FTR Holder” shall mean:

- (i) For an FTR Holder that is either a (a) privately held company, or (b) a municipality or electric cooperative, as defined in the Federal Power Act, such FTR Holder, together with any Affiliate, subsidiary or parent of the FTR Holder, any other entity that is under common ownership, wholly or partly, directly or indirectly, or has the ability to influence, directly or indirectly, the management or policies of the FTR Holder; or
- (ii) For an FTR Holder that is a publicly traded company including a wholly owned subsidiary of a publicly traded company, such FTR Holder, together with any Affiliate, subsidiary or parent of the FTR Holder, any other PJM Member has over 10% common ownership with the FTR Holder, wholly or partly, directly or indirectly, or has the ability to influence, directly or indirectly, the management or policies of the FTR Holder; or
- (iii) an FTR Holder together with any other PJM Member, including also any Affiliate, subsidiary or parent of such other PJM Member, with which it shares common ownership, wholly or partly, directly or indirectly, in any third entity which is a PJM Member (e.g., a joint venture).

**EFORd:**

“EFORd” shall have the meaning specified in the PJM Reliability Assurance Agreement.

**Electrical Distance:**

“Electrical Distance” shall mean, for a Generation Capacity Resource geographically located outside the metered boundaries of the PJM Region, the measure of distance, based on impedance and in accordance with the PJM Manuals, from the Generation Capacity Resource to the PJM Region.

**Eligible Customer:**

“Eligible Customer” shall mean:

(i) Any electric utility (including any Transmission Owner and any power marketer), Federal power marketing agency, or any person generating electric energy for sale for resale is an Eligible Customer under the Tariff. Electric energy sold or produced by such entity may be electric energy produced in the United States, Canada or Mexico. However, with respect to transmission service that the Commission is prohibited from ordering by Section 212(h) of the Federal Power Act, such entity is eligible only if the service is provided pursuant to a state requirement that the Transmission Provider or Transmission Owner offer the unbundled transmission service, or pursuant to a voluntary offer of such service by a Transmission Owner.

(ii) Any retail customer taking unbundled transmission service pursuant to a state requirement that the Transmission Provider or a Transmission Owner offer the transmission service, or pursuant to a voluntary offer of such service by a Transmission Owner, is an Eligible Customer under the Tariff. As used in Tariff, Part VI, Eligible Customer shall mean only those Eligible Customers that have submitted a Completed Application.

**Eligible Fast-Start Resource:**

“Eligible Fast-Start Resource” shall mean a Fast-Start Resource that is eligible for the application of Integer Relaxation during the calculation of Locational Marginal Prices as set forth in Tariff, Attachment K-Appendix, section 2.2.

**Emergency Action:**

“Emergency Action” shall mean any emergency action for locational or system-wide capacity shortages that either utilizes pre-emergency mandatory load management reductions or other emergency capacity, or initiates a more severe action including, but not limited to, a Voltage Reduction Warning, Voltage Reduction Action, Manual Load Dump Warning, or Manual Load Dump Action.

**Emergency Condition:**

“Emergency Condition” shall mean a condition or situation (i) that in the judgment of any Interconnection Party is imminently likely to endanger life or property; or (ii) that in the judgment of the Interconnected Transmission Owner or Transmission Provider is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Transmission System, the Interconnection Facilities, or the transmission systems or distribution systems to which the Transmission System is directly or indirectly connected; or (iii) that in the judgment of Interconnection Customer is imminently likely (as determined in a non-discriminatory manner) to cause damage to the Customer Facility or to the Customer Interconnection Facilities. System restoration and black start shall be considered Emergency Conditions, provided that a Generation Interconnection Customer is not obligated by an Interconnection Service Agreement to possess black start capability. Any condition or situation that results from lack of sufficient generating capacity to meet load requirements or that results solely from economic conditions shall not constitute an Emergency Condition, unless one or more of the enumerated conditions or situations identified in this definition also exists.

**Emergency Load Response Program:**

“Emergency Load Response Program” shall mean the program by which Curtailment Service Providers may be compensated by PJM for Demand Resources that will reduce load when dispatched by PJM during emergency conditions, and is described in Operating Agreement, Schedule 1, section 8 and the parallel provisions of Tariff, Attachment K-Appendix, section 8.

**Energy Efficiency Resource:**

“Energy Efficiency Resource” shall have the meaning specified in the PJM Reliability Assurance Agreement.

**Energy Market Opportunity Cost:**

“Energy Market Opportunity Cost” shall mean the difference between (a) the forecasted cost to operate a specific generating unit when the unit only has a limited number of available run hours due to limitations imposed on the unit by Applicable Laws and Regulations, and (b) the forecasted future Locational Marginal Price at which the generating unit could run while not violating such limitations. Energy Market Opportunity Cost therefore is the value associated with a specific generating unit’s lost opportunity to produce energy during a higher valued period of time occurring within the same compliance period, which compliance period is determined by the applicable regulatory authority and is reflected in the rules set forth in PJM Manual 15. Energy Market Opportunity Costs shall be limited to those resources which are specifically delineated in Operating Agreement, Schedule 2.

**Energy Resource:**

“Energy Resource” shall mean a Generating Facility that is not a Capacity Resource.

**Energy Settlement Area:**

“Energy Settlement Area” shall mean the bus or distribution of busses that represents the physical location of Network Load and by which the obligations of the Network Customer to PJM are settled.

**Energy Storage Resource:**

“Energy Storage Resource” shall mean a resource capable of receiving electric energy from the grid and storing it for later injection to the grid that participates in the PJM Energy, Capacity and/or Ancillary Services markets as a Market Participant.

**Energy Storage Resource Model Participant:**

“Energy Storage Resource Model Participant” shall mean an Energy Storage Resource utilizing the Energy Storage Resource Participation Model.

**Energy Storage Resource Participation Model:**

“Energy Storage Resource Participation Model” shall mean the participation model accepted by the Commission in Docket No. ER19-469-000.

**Energy Transmission Injection Rights:**

“Energy Transmission Injection Rights” shall mean the rights to schedule energy deliveries at a specified point on the Transmission System. Energy Transmission Injection Rights may be awarded only to a Merchant D.C. Transmission Facility that connects the Transmission System to another control area. Deliveries scheduled using Energy Transmission Injection Rights have rights similar to those under Non-Firm Point-to-Point Transmission Service.

**Entity Providing Supply Services to Default Retail Service Provider:**

“Entity Providing Supply Services to Default Retail Service Provider” shall mean any entity, including but not limited to a load aggregator or power marketer, providing supply services to an electric distribution company when that electric distribution company is serving as the default retail service provider, and that enters into a contract or similar obligation with such electric distribution company to serve retail customers who have not selected a competitive retail service provider.

**Environmental Laws:**

“Environmental Laws” shall mean applicable Laws or Regulations relating to pollution or protection of the environment, natural resources or human health and safety.

**Environmentally-Limited Resource:**

“Environmentally-Limited Resource” shall mean a resource which has a limit on its run hours imposed by a federal, state, or other governmental agency that will significantly limit its availability, on either a temporary or long-term basis. This includes a resource that is limited by a governmental authority to operating only during declared PJM capacity emergencies.

**Equivalent Load:**

“Equivalent Load” shall mean the sum of a Market Participant’s net system requirements to serve its customer load in the PJM Region, if any, plus its net bilateral transactions.

**Event of Default:**

“Event of Default,” as that term is used in Tariff, Attachment Q, shall mean a Financial Default, Credit Breach, or Credit Support Default.

**Exercise of Buyer-Side Market Power:**

“Exercise of Buyer-Side Market Power” shall mean anti-competitive behavior of a Capacity Market Seller with a Load Interest, or directed by an entity with a Load Interest, to uneconomically lower RPM Auction Sell Offer(s) in order to suppress RPM Auction clearing prices for the overall benefit of the Capacity Market Seller’s (and/or affiliates of Capacity Market Seller) portfolio of generation and load or that of the directing entity with a Load Interest as determined pursuant to Tariff, Attachment DD, section 5.14(h-2)(2)(B). A bilateral contract between the Capacity Market Seller and an entity with a Load Interest with the express purpose of lowering capacity market clearing prices shall be evidence of the Exercise of Buyer-Side Market Power.

**Existing Generation Capacity Resource:**

“Existing Generation Capacity Resource” shall have the meaning specified in the Reliability Assurance Agreement.

**Export Credit Exposure:**

“Export Credit Exposure” is determined for each Market Participant for a given Operating Day, and shall mean the sum of credit exposures for the Market Participant’s Export Transactions for that Operating Day and for the preceding Operating Day.

**Export Nodal Reference Price:**

“Export Nodal Reference Price” at each location is the 97th percentile, shall be, the real-time hourly integrated price experienced over the corresponding two-month period in the preceding calendar year, calculated separately for peak and off-peak time periods. The two-month time periods used in this calculation shall be January and February, March and April, May and June, July and August, September and October, and November and December.



**Export Transaction:**

“Export Transaction” shall be a transaction by a Market Participant that results in the transfer of energy from within the PJM Control Area to outside the PJM Control Area. Coordinated External Transactions that result in the transfer of energy from the PJM Control Area to an adjacent Control Area are one form of Export Transaction.

**Export Transaction Price Factor:**

“Export Transaction Price Factor” for a prospective time interval shall be the greater of (i) PJM’s forecast price for the time interval, if available, or (ii) the Export Nodal Reference Price, but shall not exceed the Export Transaction’s dispatch ceiling price cap, if any, for that time interval. The Export Transaction Price Factor for a past time interval shall be calculated in the same manner as for a prospective time interval, except that the Export Transaction Price Factor may use a tentative or final settlement price, as available. If an Export Nodal Reference Price is not available for a particular time interval, PJM may use an Export Transaction Price Factor for that time interval based on an appropriate alternate reference price.

**Export Transaction Screening:**

“Export Transaction Screening” shall be the process PJM uses to review the Export Credit Exposure of Export Transactions against the Credit Available for Export Transactions, and deny or curtail all or a portion of an Export Transaction, if the credit required for such transactions is greater than the credit available for the transactions.

**Export Transactions Net Activity:**

“Export Transactions Net Activity” shall mean the aggregate net total, resulting from Export Transactions, of (i) Spot Market Energy charges, (ii) Transmission Congestion Charges, and (iii) Transmission Loss Charges, calculated as set forth in Operating Agreement, Schedule 1 and the parallel provisions of Tariff, Attachment K-Appendix. Export Transactions Net Activity may be positive or negative.

**Extended Primary Reserve Requirement:**

“Extended Primary Reserve Requirement” shall equal the Primary Reserve Requirement in a Reserve Zone or Reserve Sub-zone, plus 190 MW, plus any additional reserves scheduled under emergency conditions necessary to address operational uncertainty. The Extended Primary Reserve Requirement is calculated in accordance with the PJM Manuals.

**Extended Summer Demand Resource:**

“Extended Summer Demand Resource” shall have the meaning specified in the Reliability Assurance Agreement.

**Extended Summer Resource Price Adder:**

“Extended Summer Resource Price Adder” shall mean, for Delivery Years through May 31, 2018, an addition to the marginal value of Unforced Capacity as necessary to reflect the price of Annual Resources and Extended Summer Demand Resources required to meet the applicable Minimum Extended Summer Resource Requirement.

**Extended Synchronized Reserve Requirement:**

“Extended Synchronized Reserve Requirement” shall equal the Synchronized Reserve Requirement in a Reserve Zone or Reserve Sub-zone, plus 190 MW, plus any additional reserves scheduled under emergency conditions necessary to address operational uncertainty. The Extended Synchronized Reserve Requirement is calculated in accordance with the PJM Manuals.

**External Market Buyer:**

“External Market Buyer” shall mean a Market Buyer making purchases of energy from the PJM Interchange Energy Market for consumption by end-users outside the PJM Region, or for load in the PJM Region that is not served by Network Transmission Service.

**External Resource:**

“External Resource” shall mean a generation resource located outside the metered boundaries of the PJM Region.

**Facilities Study:**

“Facilities Study” shall be an engineering study conducted by the Transmission Provider (in coordination with the affected Transmission Owner(s)) to: (1) determine the required modifications to the Transmission Provider’s Transmission System necessary to implement the conclusions of the System Impact Study; and (2) complete any additional studies or analyses documented in the System Impact Study or required by PJM Manuals, and determine the required modifications to the Transmission Provider’s Transmission System based on the conclusions of such additional studies. The Facilities Study shall include the cost and scheduled completion date for such modifications, that will be required to provide the requested transmission service or to accommodate a New Service Request. As used in the Interconnection Service Agreement or Construction Service Agreement, Facilities Study shall mean that certain Facilities Study conducted by Transmission Provider (or at its direction) to determine the design and specification of the Customer Funded Upgrades necessary to accommodate the New Service Customer’s New Service Request in accordance with Tariff, Part VI, section 207.

**Fast-Start Resource:**

“Fast-Start Resource” shall have the meaning set forth in Tariff, Attachment K-Appendix, section 2.2A

**Federal Power Act:**

“Federal Power Act” shall mean the Federal Power Act, as amended, 16 U.S.C. §§ 791a, et seq.

**FERC or Commission:**

“FERC” or “Commission” shall mean the Federal Energy Regulatory Commission or any successor federal agency, commission or department exercising jurisdiction over the Tariff, Operating Agreement and Reliability Assurance Agreement.

**FERC Market Rules:**

“FERC Market Rules” mean the market behavior rules and the prohibition against electric energy market manipulation codified by the Commission in its Rules and Regulations at 18 CFR §§ 1c.2 and 35.37, respectively; the Commission-approved PJM Market Rules and any related proscriptions or any successor rules that the Commission from time to time may issue, approve or otherwise establish.

**Final Offer:**

“Final Offer” shall mean the offer on which a resource was dispatched by the Office of the Interconnection for a particular clock hour for the Operating Day.

**Final RTO Unforced Capacity Obligation:**

“Final RTO Unforced Capacity Obligation” shall mean the capacity obligation for the PJM Region, determined in accordance with RAA, Schedule 8.

**Financial Close:**

“Financial Close” shall mean the Capacity Market Seller has demonstrated that the Capacity Market Seller or its agent has completed the act of executing the material contracts and/or other documents necessary to (1) authorize construction of the project and (2) establish the necessary funding for the project under the control of an independent third-party entity. A sworn, notarized certification of an independent engineer certifying to such facts, and that the engineer has personal knowledge of, or has engaged in a diligent inquiry to determine, such facts, shall be sufficient to make such demonstration. For resources that do not have external financing, Financial Close shall mean the project has full funding available, and that the project has been duly authorized to proceed with full construction of the material portions of the project by the appropriate governing body of the company funding such project. A sworn, notarized certification by an officer of such company certifying to such facts, and that the officer has personal knowledge of, or has engaged in a diligent inquiry to determine, such facts, shall be sufficient to make such demonstration.

**Financial Default:**

“Financial Default” shall mean (a) the failure of a Member or Transmission Customer to make any payment for obligations under the Agreements when due, including but not limited to an invoice payment that has not been cured or remedied after notice has been given and any cure period has elapsed, (b) a bankruptcy proceeding filed by a Member, Transmission Customer or its Guarantor, or filed against a Member, Transmission Customer or its Guarantor and to which the Member, Transmission Customer or Guarantor, as applicable, acquiesces or that is not dismissed within 60 days, (c) a Member, Transmission Customer or its Guarantor, if any, is unable to meet its financial obligations as they become due, or (d) a Merger Without Assumption occurs in respect of the Member, Transmission Customer or any Guarantor of such Member or Transmission Customer.

**Financial Transmission Right:**

“Financial Transmission Right” or “FTR” shall mean a right to receive Transmission Congestion Credits as specified in Operating Agreement, Schedule 1, section 5.2.2 and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.2.

**Financial Transmission Right Obligation:**

“Financial Transmission Right Obligation” shall mean a right to receive Transmission Congestion Credits as specified in Operating Agreement, Schedule 1, section 5.2.2(b), and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.2(b).

**Financial Transmission Right Option:**

“Financial Transmission Right Option” shall mean a right to receive Transmission Congestion Credits as specified in Operating Agreement, Schedule 1, section 5.2.2(c), and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.2(c).

**Firm Point-To-Point Transmission Service:**

“Firm Point-To-Point Transmission Service” shall mean Transmission Service under the Tariff that is reserved and/or scheduled between specified Points of Receipt and Delivery pursuant to Tariff, Part II.

**Firm Transmission Feasibility Study:**

“Firm Transmission Feasibility Study” shall mean a study conducted by the Transmission Provider in accordance with Tariff, Part II, section 19.3 and Tariff, Part III, section 32.3.

**Firm Transmission Withdrawal Rights:**

“Firm Transmission Withdrawal Rights” shall mean the rights to schedule energy and capacity withdrawals from a Point of Interconnection of a Merchant Transmission Facility with the Transmission System. Firm Transmission Withdrawal Rights may be awarded only to a Merchant D.C. Transmission Facility that connects the Transmission System with another

control area. Withdrawals scheduled using Firm Transmission Withdrawal Rights have rights similar to those under Firm Point-to-Point Transmission Service.

**First Incremental Auction:**

“First Incremental Auction” shall mean an Incremental Auction conducted 20 months prior to the start of the Delivery Year to which it relates.

**Flexible Resource:**

“Flexible Resource” shall mean a generating resource that must have a combined Start-up Time and Notification Time of less than or equal to two hours; and a Minimum Run Time of less than or equal to two hours.

**Forecast Pool Requirement:**

“Forecast Pool Requirement” shall have the meaning specified in the Reliability Assurance Agreement.

**Foreign Guaranty:**

“Foreign Guaranty” shall mean a Corporate Guaranty provided by an Affiliate of a Participant that is domiciled in a foreign country, and meets all of the provisions of Tariff, Attachment Q.

**Form 715 Planning Criteria:**

“Form 715 Planning Criteria” shall have the same meaning provided in the Operating Agreement.

**Forward Daily Natural Gas Prices:**

“Forward Daily Natural Gas Prices” shall have the meaning provided in Tariff, Attachment DD, section 5.10(a)(v-1)(E).

**Forward Hourly Ancillary Services Prices:**

“Forward Hourly Ancillary Services Prices” shall have the meaning provided in Tariff, Attachment DD, section 5.10(a)(v-1)(D).

**Forward Hourly LMPs:**

“Forward Hourly LMPs” shall have the meaning provided in Tariff, Attachment DD, section 5.10(a)(v-1)(C).

**FTR Credit Limit:**

“FTR Credit Limit” shall mean the amount of credit established with PJMSettlement that an FTR Participant has specifically designated to be used for FTR activity in a specific customer account. Any such credit so set aside shall not be considered available to satisfy any other credit requirement the FTR Participant may have with PJMSettlement.

**FTR Credit Requirement:**

“FTR Credit Requirement” shall mean the amount of credit that a Participant must provide in order to support the FTR positions that it holds and/or for which it is bidding. The FTR Credit Requirement shall not include months for which the invoicing has already been completed, provided that PJMSettlement shall have up to two Business Days following the date of the invoice completion to make such adjustments in its credit systems. FTR Credit Requirements are calculated and applied separately for each separate customer account.

**FTR Flow Undiversified:**

“FTR Flow Undiversified” shall have the meaning established in Tariff, Attachment Q, section VI.C.6.

**FTR Historical Value:**

For each FTR for each month, “FTR Historical Value” shall mean the weighted average of historical values over three years for the FTR path using the following weightings: 50% - most recent year; 30% - second year; 20% - third year.

**FTR Holder:**

“FTR Holder” shall mean the PJM Member that has acquired and possesses an FTR.

**FTR Monthly Credit Requirement Contribution:**

For each FTR, for each month, “FTR Monthly Credit Requirement Contribution” shall mean the total FTR cost for the month, prorated on a daily basis, less the FTR Historical Value for the month. For cleared FTRs, this contribution may be negative; prior to clearing, FTRs with negative contribution shall be deemed to have zero contribution.

**FTR Net Activity:**

“FTR Net Activity” shall mean the aggregate net value of the billing line items for auction revenue rights credits, FTR auction charges, FTR auction credits, and FTR congestion credits, and shall also include day-ahead and balancing/real-time congestion charges up to a maximum net value of the sum of the foregoing auction revenue rights credits, FTR auction charges, FTR auction credits and FTR congestion credits.

**FTR Participant:**

“FTR Participant” shall mean any Market Participant that provides or is required to provide Collateral in order to participate in PJM’s FTR market.

**FTR Portfolio Auction Value:**

“FTR Portfolio Auction Value” shall mean for each customer account of a Market Participant, the sum, calculated on a monthly basis, across all FTRs, of the FTR price times the FTR volume in MW.

**Fuel Cost Policy:**

“Fuel Cost Policy” shall mean the document provided by a Market Seller to PJM and the Market Monitoring Unit in accordance with PJM Manual 15 and Operating Agreement, Schedule 2, which documents the Market Seller’s method used to price fuel for calculation of the Market Seller’s cost-based offers for a generation resource.

**Full Notice to Proceed:**

“Full Notice to Proceed” shall mean that all material third party contractors have been given the notice to proceed with construction by the Capacity Market Seller or its agent, with a guaranteed completion date backed by liquidated damages.

## **Definitions – L – M – N**

### **Legacy Policy:**

“Legacy Policy” shall mean any legislative, executive, or regulatory action that specifically directs a payment outside of PJM Markets to a designated or prospective Generation Capacity Resource and the enactment of such action predates October 1, 2021, regardless of when any implementing governmental action to effectuate the action to direct payment outside of PJM Markets occurs.

### **Limited Demand Resource:**

“Limited Demand Resource” shall have the meaning specified in the Reliability Assurance Agreement.

### **Limited Demand Resource Reliability Target:**

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



not be called (based on the applicable operating reserve margin for the PJM Region and for the relevant LDAs) for more than six hours over any one or more of the tested peak days. Second, PJM adopts the lowest result from these three tests as the Limited Demand Resource Reliability Target. The Limited Demand Resource Reliability Target shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the DR Factor] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

**Limited Resource Constraint:**

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

**Limited Resource Price Decrement:**

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

**List of Approved Contractors:**

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

**Load Interest:**

“Load Interest” shall mean, for the purposes of the minimum offer price rule, responsibility for serving load within the PJM Region, whether by the Capacity Market Seller, an affiliate of the Capacity Market Seller, or by an entity with which the Capacity Market Seller is in contractual privity with respect to the subject Generation Capacity Resource.

**Load Management:**

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

**Load Management Event:**

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

**Load Ratio Share:**

“Load Ratio Share” shall mean the ratio of a Transmission Customer’s Network Load to the Transmission Provider’s total load.

**Load Reduction Event:**

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

**Load Serving Charging Energy:**

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

**Load Serving Entity (LSE):**

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

**Load Shedding:**

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

**Local Upgrades:**

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

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

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

**Location:**

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

**LOC Deviation:**

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

**Locational Deliverability Area (LDA):**

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

**Locational Deliverability Area Reliability Requirement:**

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

**Locational Price Adder:**

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

**Locational Reliability Charge:**

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

**Locational UCAP:**

“Locational UCAP” shall mean unforced capacity that a Member with available uncommitted capacity sells in a bilateral transaction to a Member that previously committed capacity through an RPM Auction but now requires replacement capacity to fulfill its RPM Auction commitment. The Locational UCAP Seller retains responsibility for performance of the resource providing such replacement capacity.

**Locational UCAP Seller:**

“Locational UCAP Seller” shall mean a Member that sells Locational UCAP.

**Long-lead Project:**

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

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

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

**Loss Price:**

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

**M2M Flowgate:**

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

**Maintenance Adder:**

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

**Manual Load Dump Action:**

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

**Manual Load Dump Warning:**

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

**Marginal Value:**

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

**Market Monitor:**

“Market Monitor” means the head of the Market Monitoring Unit.

**Market Monitoring Unit or MMU:**

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

**Market Monitoring Unit Advisory Committee or MMU Advisory Committee:**

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

**Market Operations Center:**

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

**Market Participant:**

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

**Market Participant Energy Injection:**

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

**Market Participant Energy Withdrawal:**

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

**Market Seller Offer Cap:**

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

**Market Violation:**

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

**Material Modification:**

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

**Maximum Daily Starts:**

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

**Maximum Emergency:**

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

**Maximum Facility Output:**

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

**Maximum Generation Emergency:**

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

**Maximum Generation Emergency Alert:**

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

**Maximum Run Time:**

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

**Maximum Weekly Starts:**

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

**Member:**

“Member” shall have the meaning provided in the Operating Agreement.

**Merchant A.C. Transmission Facilities:**

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

**Merchant D.C. Transmission Facilities:**

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

**Merchant Network Upgrades:**

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

**Merchant Transmission Facilities:**

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

**Merchant Transmission Provider:**

“Merchant Transmission Provider” shall mean an Interconnection Customer that (1) owns, controls, or controls the rights to use the transmission capability of, Merchant D.C. Transmission Facilities and/or Controllable A.C. Merchant Transmission Facilities that connect the Transmission System with another control area, (2) has elected to receive Transmission Injection Rights and Transmission Withdrawal Rights associated with such facility pursuant to Tariff, Part IV, section 36, and (3) makes (or will make) the transmission capability of such facilities



available for use by third parties under terms and conditions approved by the Commission and stated in the Tariff, consistent with Tariff, section 38.

**Metering Equipment:**

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

**Minimum Annual Resource Requirement:**

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

**Minimum Down Time:**

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

**Minimum Extended Summer Resource Requirement:**

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

**Minimum Generation Emergency:**

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

**Minimum Participation Requirements:**

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

**Minimum Run Time:**

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

**MISO:**

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

**MOPR Floor Offer Price:**

“MOPR Floor Offer Price” shall mean a minimum offer price applicable to certain Market Seller's Capacity Resources under certain conditions, as determined in accordance with Tariff, Attachment DD, sections 5.14(h), 5.14(h-1), and 5.14(h-2).

**Multi-Driver Project:**

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

**Native Load Customers:**

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

**NERC:**

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

**NERC Interchange Distribution Calculator:**

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

**Net Benefits Test:**

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

**Net Cost of New Entry:**

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

**Net Obligation:**

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

**Net Sell Position:**

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

**Network Customer:**

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

**Network External Designated Transmission Service:**

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

**Network Integration Transmission Service:**

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

**Network Load:**

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

**Network Operating Agreement:**

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

**Network Operating Committee:**

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

**Network Resource:**

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

**Network Service User:**

“Network Service User” shall mean an entity using Network Transmission Service.

**Network Transmission Service:**

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

**Network Upgrades:**

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

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

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

**Neutral Party:**

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

**New Entry Capacity Resource with State Subsidy:**

“New Entry Capacity Resource with State Subsidy” shall mean (1) starting with the 2022/2023 Delivery Year, the MWs (in installed capacity) comprising a Capacity Resource with State Subsidy that have not cleared in an RPM Auction pursuant to its Sell Offer at or above its resource-specific MOPR Floor Offer Price or the applicable default New Entry MOPR Floor Offer Price or (2) starting with the Base Residual Auction for the 2022/2023 Delivery Year, any of those MWs (in installed capacity) comprising a Capacity Resource with State Subsidy that was not included in an FRR Capacity Plan at the time of the Base Residual Auction or the subject of a Sell Offer in a Base Residual Auction occurring for a Delivery Year after it last cleared an RPM Auction and since then has yet to clear an RPM Auction pursuant to its Sell

Offer at or above its resource-specific MOPR Floor Offer Price or the applicable default New Entry MOPR Floor Offer Price. Notwithstanding the foregoing, any Capacity Resource that previously cleared an RPM Auction before it became entitled to receive a State Subsidy shall not be deemed a New Entry Capacity Resource, unless, starting with the Base Residual Auction for the 2022/2023 Delivery Year, the Capacity Resource with State Subsidy was not the subject of a Sell Offer in a Base Residual Auction or included in an FRR Capacity Plan at the time of the Base Residual Auction for a Delivery Year after it last cleared an RPM Auction.

**New PJM Zone(s):**

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

**New Service Customers:**

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

**New Service Request:**

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

**New Services Queue:**

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

**New York ISO or NYISO:**

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

**Nodal Reference Price:**

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

**No-load Cost:**

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

**Nominal Rated Capability:**

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

**Nominated Demand Resource Value:**

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

**Nominated Energy Efficiency Value:**

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

**Non-Dispatched Charging Energy:**

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

**Non-Firm Point-To-Point Transmission Service:**

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

**Non-Firm Sale:**

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

**Non-Firm Transmission Withdrawal Rights:**

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

**Non-Performance Charge:**

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

**Nonincumbent Developer:**

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

**Non-Regulatory Opportunity Cost:**

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

**Non-Retail Behind The Meter Generation:**

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

**Non-Synchronized Reserve:**

“Non-Synchronized Reserve” shall mean the reserve capability of non-emergency generation resources that can be converted fully into energy within ten minutes of a request from the Office



of the Interconnection dispatcher, and is provided by equipment that is not electrically synchronized to the Transmission System.

**Non-Synchronized Reserve Event:**

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

**Non-Variable Loads:**

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

**Non-Zone Network Load:**

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

**Normal Maximum Generation:**

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

**Normal Minimum Generation:**

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

## **Definitions – R - S**

### **Ramping Capability:**

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

### **Real-time Congestion Price:**

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

### **Real-time Loss Price:**

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

### **Real-time Energy Market:**

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

### **Real-time Offer:**

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

### **Real-time Prices:**

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

### **Real-time Settlement Interval:**

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

### **Real-time System Energy Price:**

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

### **Reasonable Efforts:**

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

**Receiving Party:**

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

**Referral:**

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

**Reference Resource:**

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

**Regional Entity:**

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

**Regional Transmission Expansion Plan:**

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

**Regional Transmission Group (RTG):**

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

**Regulation:**

“Regulation” shall mean the capability of a specific generation resource or Demand Resource with appropriate telecommunications, control and response capability to separately increase and

decrease its output or adjust load in response to a regulating control signal, in accordance with the specifications in the PJM Manuals.

**Regulation Zone:**

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

**Relevant Electric Retail Regulatory Authority:**

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

**Reliability Assurance Agreement or PJM Reliability Assurance Agreement:**

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

**Reliability Pricing Model Auction:**

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

**Required Transmission Enhancements:**

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

**Reserved Capacity:**

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

**Reserve Penalty Factor:**

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

**Reserve Sub-zone:**

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

**Reserve Zone:**

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

**Residual Auction Revenue Rights:**

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

**Residual Metered Load:**

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

**Resource Substitution Charge:**

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

**Revenue Data for Settlements:**

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

**RPM Seller Credit:**

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

**Scheduled Incremental Auctions:**

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

**Schedule of Work:**

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

**Scope of Work:**

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

**Seasonal Capacity Performance Resource:**

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

**Secondary Systems:**

“Secondary Systems” shall mean control or power circuits that operate below 600 volts, AC or DC, including, but not limited to, any hardware, control or protective devices, cables,

conductors, electric raceways, secondary equipment panels, transducers, batteries, chargers, and voltage and current transformers.

**Second Incremental Auction:**

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

**Security:**

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

**Segment:**

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

**Self-Supply:**

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

**Self-Supply Entity:**

“Self-Supply Entity” shall mean the following types of Load Serving Entity that operate under long-standing business models: single customer entity, public power entity, or vertically integrated utility, where “vertically integrated utility” means a utility that owns generation, includes such generation in its regulated rates, and earns a regulated return on its investment in such generation or receives any cost recovery for such generation through bilateral contracts; “single customer entity” means a Load Serving Entity that serves at retail only customers that are under common control with such Load Serving Entity, where such control means holding 51% or more of the voting securities or voting interests of the Load Serving Entity and all its retail customers; and “public power entity” means cooperative and municipal utilities, including public power supply entities comprised of either or both of the same and rural electric cooperatives, and joint action agencies.

**Self-Supply Seller:**

“Self-Supply Seller” shall mean, for purposes of evaluating Buyer-Side Market Power, the following types of Load Serving Entities that operate under long-standing business models: vertically integrated utility or public power entity, where “vertically integrated utility” means a utility that owns generation, includes such generation in its state-regulated rates, and earns a state-regulated return on its investment in such generation; and “public power entity” means electric cooperatives that are either rate regulated by the state or have their long-term resource plan approved or otherwise reviewed and accepted by a Relevant Electric Retail Regulatory Authority and municipal utilities or joint action agencies that are subject to direct regulation by a Relevant Electric Retail Regulatory Authority.

**Sell Offer:**

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

**Service Agreement:**

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

**Service Commencement Date:**

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

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

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

**Short-term Project:**

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

**Short-Term Resource Procurement Target:**

“Short-Term Resource Procurement Target” shall mean, for Delivery Years through May 31, 2018, as to the PJM Region, for purposes of the Base Residual Auction, 2.5% of the PJM Region Reliability Requirement determined for such Base Residual Auction, for purposes of the First Incremental Auction, 2% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction; and, for purposes of the Second Incremental Auction, 1.5% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual



Auction; and, as to any Zone, an allocation of the PJM Region Short-Term Resource Procurement Target based on the Preliminary Zonal Forecast Peak Load, reduced by the amount of load served under the FRR Alternative. For any LDA, the LDA Short-Term Resource Procurement Target shall be the sum of the Short-Term Resource Procurement Targets of all Zones in the LDA.

**Short-Term Resource Procurement Target Applicable Share:**

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

**Site:**

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

**Small Commercial Customer:**

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

**Small Generation Resource:**

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

**Small Inverter Facility:**

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

**Small Inverter ISA:**

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

**Special Member:**

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

**Spot Market Backup:**

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

**Spot Market Energy:**

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

**Start Additional Labor Costs:**

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

**Start-Up Costs:**

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

**State:**

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

**State Commission:**

“State Commission” shall mean any state regulatory agency having jurisdiction over retail electricity sales in any State in the PJM Region.

**State Estimator:**

“State Estimator” shall mean the computer model of power flows specified in Operating Agreement, Schedule 1, section 2.3 and the parallel provisions of Tariff, Attachment K-Appendix, section 2.3.

**State Subsidy:**

“State Subsidy” shall mean a direct or indirect payment, concession, rebate, subsidy, non-bypassable consumer charge, or other financial benefit that is as a result of any action, mandated process, or sponsored process of a state government, a political subdivision or agency of a state, or an electric cooperative formed pursuant to state law, and that

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

Notwithstanding the foregoing, State Subsidy shall not include (a) payments, concessions, rebates, subsidies, or incentives designed to incent, or participation in a program, contract or other arrangement that utilizes criteria designed to incent or promote, general industrial development in an area or designed to incent siting facilities in that county or locality rather than another county or locality; (b) state action that imposes a tax or assesses a charge utilizing the parameters of a regional program on a given set of resources notwithstanding the tax or cost having indirect benefits on resources not subject to the tax or cost (e.g., Regional Greenhouse Gas Initiative); (c) any indirect benefits to a Capacity Resource as a result of any transmission project approved as part of the Regional Transmission Expansion Plan; (d) any contract, legally enforceable obligation, or rate pursuant to the Public Utility Regulatory Policies Act or any other state-administered federal regulatory program (e.g., the Cross-State Air Pollution Rule); (e) any revenues from the sale or allocation, either direct or indirect, to an Entity Providing Supply Services to Default Retail Service Provider where such entity’s obligations was awarded through a state default procurement auction that was subject to independent oversight by a consultant or manager who certifies that the auction was conducted through a non-discriminatory and competitive bidding process, subject to the below condition, and provided further that nothing herein would exempt a Capacity Resource that would otherwise be subject to the minimum offer price rule pursuant to this Tariff; (f) any revenues for providing capacity as part of an FRR Capacity Plan or through bilateral transactions with FRR Entities; or (g) any voluntary and arm’s length bilateral transaction (including but not limited to those reported pursuant to Tariff, Attachment DD, section 4.6), such as a power purchase agreement or other similar contract where the buyer is a Self-Supply Entity and the transaction is (1) a short term transaction (one-year or less) or (2) a long-term transaction that is the result of a competitive process that was not fuel-specific and is not used for the purpose of supporting uneconomic construction,

development, or operation of the subject Capacity Resource, provided however that if the Self-Supply Entity is responsible for offering the Capacity Resource into an RPM Auction, the specified amount of installed capacity purchased by such Self-Supply Entity shall be considered to receive a State Subsidy in the same manner, under the same conditions, and to the same extent as any other Capacity Resource of a Self-Supply Entity. For purposes of subsection (e) of this definition, a state default procurement auction that has been certified to be a result of a non-discriminatory and competitive bidding process shall:

- (i) have no conditions based on the ownership (except supplier diversity requirements or limits), location (except to meet PJM deliverability requirements), affiliation, fuel type, technology, or emissions of any resources or supply (except state-mandated renewable portfolio standards for which Capacity Resources are separately subject to the minimum offer price rule or eligible for an exemption);
- (ii) result in contracts between an Entity Providing Supply Services to Default Retail Service Provider and the electric distribution company for a retail default generation supply product and none of those contracts require that the retail obligation be sourced from any specific Capacity Resource or resource type as set forth in subsection (i) above; and
- (iii) establish market-based compensation for a retail default generation supply product that retail customers can avoid paying for by obtaining supply from a competitive retail supplier of their choice.

#### **State of Charge:**

“State of Charge” shall mean the quantity of physical energy stored in an Energy Storage Resource Model Participant in proportion to its maximum State of Charge capability. State of Charge is quantified as defined in the PJM Manuals.

#### **State of Charge Management:**

“State of Charge Management” shall mean the control of State of Charge of an Energy Storage Resource Market Participant using minimum and maximum charge and discharge limits, changes in operating mode, charging and discharging offer curves, and self-scheduling of non-dispatchable purchases and sales of energy in the PJM markets. State of Charge Management shall not interfere with an Energy Storage Resource Model Participant’s obligation to follow PJM dispatch, consistent with all other resources.

#### **Station Power:**

“Station Power” shall mean energy used for operating the electric equipment on the site of a generation facility located in the PJM Region or for the heating, lighting, air-conditioning and office equipment needs of buildings on the site of such a generation facility that are used in the operation, maintenance, or repair of the facility. Station Power does not include any energy (i) used to power synchronous condensers; (ii) used for pumping at a pumped storage facility; (iii) used in association with restoration or black start service; or (iv) that is Direct Charging Energy.

**Sub-Annual Resource Constraint:**

“Sub-Annual Resource Constraint” shall mean, for the 2017/2018 Delivery Year and for FRR Capacity Plans the 2017/2018 and 2018/2019 Delivery Years, for the PJM Region or for each LDA for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for a Delivery Year, a limit on the total amount of Unforced Capacity that can be committed as Limited Demand Resources and Extended Summer Demand Resources for the 2017/2018 Delivery Year in the PJM Region or in such LDA, calculated as the Sub-Annual Resource Reliability Target for the PJM Region or for such LDA, respectively, minus the Short-Term Resource Procurement Target for the PJM Region or for such LDA, respectively.

**Sub-Annual Resource Price Decrement:**

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

**Sub-Annual Resource Reliability Target:**

“Sub-Annual Reliability Target” for the PJM Region or an LDA, shall mean the maximum amount of the combination of Extended Summer Demand Resources and Limited Demand Resources in Unforced Capacity determined by PJM to be consistent with the maintenance of reliability, stated in Unforced Capacity, that shall be used to calculate the Minimum Annual Resource Requirement for Delivery Years through May 31, 2017 and the Sub-Annual Resource Constraint for the 2017/2018 and 2018/2019 Delivery Years. As more fully set forth in the PJM Manuals, PJM calculates the Sub-Annual Resource Reliability Target, by first determining a reference annual loss of load expectation (“LOLE”) assuming no Demand Resources. The calculation for the unconstrained portion of the PJM Region uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast and iteratively shifting the load distributions to result in the Installed Reserve Margin established for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). The calculation for each relevant LDA uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Capacity Emergency Transfer Objective study for the Delivery Year in question). For the relevant LDA calculation, the weekly capacity distributions are adjusted to reflect the Capacity Emergency Transfer Limit for the Delivery Year in question.

For both the PJM Region and LDA analyses, PJM then models the commitment of varying amounts of DR (displacing otherwise committed generation) as interruptible from May 1 through October 31 and unavailable from November 1 through April 30 and calculates the LOLE at each DR level. The Extended Summer DR Reliability Target is the DR amount, stated as a percentage of the unrestricted peak load, that produces no more than a ten percent increase in the LOLE,

compared to the reference value. The Sub-Annual Resource Reliability Target shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the DR Factor] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

**Sub-meter:**

“Sub-meter” shall mean a metering point for electricity consumption that does not include all electricity consumption for the end-use customer as defined by the electric distribution company account number. PJM shall only accept sub-meter load data from end-use customers for measurement and verification of Regulation service as set forth in the Economic Load Response rules and PJM Manuals.

**Summer-Period Capacity Performance Resource:**

“Summer-Period Capacity Performance Resource” shall have the same meaning specified in Tariff, Attachment DD, section 5.5A.

**Surplus Interconnection Customer:**

“Surplus Interconnection Customer” shall mean either an Interconnection Customer whose Generating Facility is already interconnected to the PJM Transmission System or one of its affiliates, or an unaffiliated entity that submits a Surplus Interconnection Request to utilize Surplus Interconnection Service within the Transmission System in the PJM Region. A Surplus Interconnection Customer is not a New Service Customer.

**Surplus Interconnection Request:**

“Surplus Interconnection Request” shall mean a request submitted by a Surplus Interconnection Customer, pursuant to Tariff, Attachment RR, to utilize Surplus Interconnection Service within the Transmission System in the PJM Region. A Surplus Interconnection Request is not a New Service Request.

**Surplus Interconnection Service:**

“Surplus Interconnection Service” shall mean any unneeded portion of Interconnection Service established in an Interconnection Service Agreement, such that if Surplus Interconnection Service is utilized, the total amount of Interconnection Service at the Point of Interconnection would remain the same.

**Switching and Tagging Rules:**

“Switching and Tagging Rules” shall mean the switching and tagging procedures of Interconnected Transmission Owners and Interconnection Customer as they may be amended from time to time.

**Synchronized Reserve:**

“Synchronized Reserve” shall mean the reserve capability of generation resources that can be converted fully into energy or Demand Resources whose demand can be reduced within ten minutes from the request of the Office of the Interconnection dispatcher, and is provided by equipment that is electrically synchronized to the Transmission System.

**Synchronized Reserve Event:**

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

**Synchronized Reserve Requirement:**

“Synchronized Reserve Requirement” shall mean the megawatts required to be maintained in a Reserve Zone or Reserve Sub-zone as Synchronized Reserve, absent any increase to account for additional reserves scheduled to address operational uncertainty. The Synchronized Reserve Requirement is calculated in accordance with the PJM Manuals.

**System Condition:**

“System Condition” shall mean a specified condition on the Transmission Provider’s system or on a neighboring system, such as a constrained transmission element or flowgate, that may trigger Curtailment of Long-Term Firm Point-to-Point Transmission Service using the curtailment priority pursuant to Tariff, Part II, section 13.6. Such conditions must be identified in the Transmission Customer’s Service Agreement.

**System Energy Price:**

“System Energy Price” shall mean the energy component of the Locational Marginal Price, which is the price at which the Market Seller has offered to supply an additional increment of energy from a resource, calculated as specified in Operating Agreement, Schedule 1, section 2 and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

**System Impact Study:**

“System Impact Study” shall mean an assessment by the Transmission Provider of (i) the adequacy of the Transmission System to accommodate a Completed Application, an Interconnection Request or an Upgrade Request, (ii) whether any additional costs may be incurred in order to provide such transmission service or to accommodate an Interconnection Request, and (iii) with respect to an Interconnection Request, an estimated date that an Interconnection Customer’s Customer Facility can be interconnected with the Transmission

System and an estimate of the Interconnection Customer's cost responsibility for the interconnection; and (iv) with respect to an Upgrade Request, the estimated cost of the requested system upgrades or expansion, or of the cost of the system upgrades or expansion, necessary to provide the requested incremental rights.

**System Protection Facilities:**

“System Protection Facilities” shall refer to the equipment required to protect (i) the Transmission System, other delivery systems and/or other generating systems connected to the Transmission System from faults or other electrical disturbance occurring at or on the Customer Facility, and (ii) the Customer Facility from faults or other electrical system disturbance occurring on the Transmission System or on other delivery systems and/or other generating systems to which the Transmission System is directly or indirectly connected. System Protection Facilities shall include such protective and regulating devices as are identified in the Applicable Technical Requirements and Standards or that are required by Applicable Laws and Regulations or other Applicable Standards, or as are otherwise necessary to protect personnel and equipment and to minimize deleterious effects to the Transmission System arising from the Customer Facility.



## 5.14 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) an adjustment, if required, to account for Resource Make-Whole Payments; and (5) an adjustment, if required to provide sufficient revenue for payment of any PRD Credits, all as determined in accordance with the optimization algorithm.

ii) The Office of the Interconnection shall calculate and post the Adjusted Zonal Capacity Price following each Incremental Auction. The Adjusted Zonal Capacity Price for each Zone shall equal the sum of: (1) the average marginal value of system capacity weighted by the Unforced Capacity cleared in all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); (2) the average Locational Price Adder weighted by the Unforced Capacity cleared in all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); (3) an adjustment, if required, to account for adders paid to Annual Resources and Extended Summer Demand Resources for all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); (4) an adjustment, if required, to account for Resource Make-Whole Payments for all actions previously conducted (excluding any Resource Make-Whole Payments to be charged to the buyers of replacement capacity); and (5) an adjustment, if required to provide sufficient revenue for payment of any PRD Credits. The Adjusted Zonal Capacity Price may decrease if Unforced Capacity is decommitted or the Resource Clearing Price decreases in an Incremental Auction.

iii) The Office of the Interconnection shall calculate and post the Final Zonal Capacity Price for each Delivery Year after the final auction is held for such Delivery Year, as set forth above. The Final Zonal Capacity Price for each Zone shall equal the Adjusted Zonal Capacity Price, as further adjusted to reflect any decreases in the Nominated Demand Resource Value of any existing Demand Resource cleared in the Base Residual Auction and Second Incremental Auction.

g) Resource Substitution Charge

Each Capacity Market Buyer in an Incremental Auction securing replacement capacity shall pay a Resource Substitution Charge equal to the Capacity Resource Clearing Price resulting from such auction multiplied by the megawatt quantity of Unforced Capacity purchased by such Market Buyer in such auction.

h) Minimum Offer Price Rule for Certain New Generation Capacity Resources that are not Capacity Resources with State Subsidy for 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 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.

<b>Resource Type</b>	<b>Gross Cost of New Entry (2022/2023 \$/ MW-day) (Nameplate)</b>
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.

<b>Existing Resource Type</b>	<b>Default Gross ACR (2022/2023 (\$/MW-day) (Nameplate)</b>
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 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 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 Delivery Year, net of estimated net energy and ancillary service revenues for the resource type and Zone in which the resource is located.

<b>Resource Type</b>	<b>Gross Cost of New Entry (2022/2023 \$/ MW-day) (Nameplate)</b>
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

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. 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; and

(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.

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 Delivery Year 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 subsection (ii) below.

<b>Existing Resource Type</b>	<b>Default Gross ACR (2022/2023) (\$/MW-day) (Nameplate)</b>
Nuclear - single	\$697
Nuclear - dual	\$445
Coal	\$80
Combined Cycle	\$56
Combustion Turbine	\$50
Solar PV (fixed and tracking)	\$40
Wind Onshore	\$83

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) 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)(3)(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 Generation Capacity Resource that has previously cleared an RPM Auction for any Delivery Year and where such Sell Offer is 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 unit-specific MOPR Floor Offer Price for such Capacity Resource pursuant to Tariff, Attachment DD, section 5.14(h-2)(4) 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. 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 unit-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) 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 unit-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.

(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

$(\text{Export Path Import} * \text{Export Reserved Capacity}) /$

$(\text{Export Reserved Capacity} + \text{Daily Unforced Capacity Obligations of all LSEs in such Zone}).$

Where:

“Export Path Import” means the megawatts of Unforced Capacity imported into the export interface Zone from the Zone in which the resource designated for export is located.

If more than one Zone forms the interface with such Control Area, then the amount of Export Reserved Capacity shall be apportioned among such Zones for purposes of the above calculation in the same manner as set forth in subsection (i)(1) above.

### (3) Distribution of Revenues

Any revenues collected from the Capacity Export Charge with respect to any capacity export for a Delivery Year, less the credit provided in subsection (i)(2) for such Delivery Year, shall be distributed to the Load Serving Entities in the export-interface Zone that were assessed a

Locational Reliability Charge for such Delivery Year, pro rata based on the Daily Unforced Capacity Obligations of such Load-serving Entities in such Zone during such Delivery Year. If more than one Zone forms the interface with such Control Area, then the revenues shall be apportioned among such Zones for purposes of the above calculation in the same manner as set forth in subsection (i)(1) above.

### **5.14A [Reserved.]**

### **5.14B Generating Unit Capability Verification Test Requirements Transition Provision for RPM Delivery Years 2014/2015, 2015/2016, and 2016/2017**

A. This transition provision applies only with respect to Generation Capacity Resources with existing capacity commitments for the 2014/2015, 2015/2016, or 2016/2017 Delivery Years that experience reductions in verified installed capacity available for sale as a direct result of revised generating unit capability verification test procedures effective with the summer 2014 capability tests, as set forth in the PJM Manuals. A Generation Capacity Resource meeting the description of the preceding sentence, and the Capacity Market Seller of such a resource, are hereafter in this section 5.14B referred to as an “Affected Resource” and an “Affected Resource Owner,” respectively.

B. For each of its Affected Resources, an Affected Resource Owner is required to provide documentation to the Office of the Interconnection sufficient to show a reduction in installed capacity value as a direct result of the revised capability test procedures. Upon acceptance by

the Office of the Interconnection, the Affected Resource's installed capacity value will be updated in the eRPM system to reflect the reduction, and the Affected Resource's Capacity Interconnection Rights value will be updated to reflect the reduction, effective June 1, 2014. The reduction's impact on the Affected Resource's existing capacity commitments for the 2014/2015 Delivery Year will be determined in Unforced Capacity terms, using the final EFORD value established by the Office of the Interconnection for the 2014/2015 Delivery Year as applied to the Third Incremental Auction for the 2014/2015 Delivery Year, to convert installed capacity to Unforced Capacity. The reduction's impact on the Affected Resource's existing capacity commitments for each of the 2015/2016 and 2016/2017 Delivery Years will be determined in Unforced Capacity terms, using the EFORD value from each Sell Offer in each applicable RPM Auction, applied on a pro-rata basis, to convert installed capacity to Unforced Capacity. The Unforced Capacity impact for each Delivery Year represents the Affected Resource's capacity commitment shortfall, resulting wholly and directly from the revised capability test procedures, for which the Affected Resource Owner is subject to a Capacity Resource Deficiency Charge for the Delivery Year, as described in Tariff, Attachment DD, section 8 , unless the Affected Resource Owner (i) provides replacement Unforced Capacity, as described in Tariff, Attachment DD, section 8.1, prior to the start of the Delivery Year to resolve the Affected Resource's total capacity commitment shortfall; or (ii) requests relief from Capacity Resource Deficiency Charges that result wholly and directly from the revised capability test procedures by electing the transition mechanism described in this section 5.14B ("Transition Mechanism").

C. Under the Transition Mechanism, an Affected Resource Owner may elect to have the Unforced Capacity commitments for all of its Affected Resources reduced for the 2014/2015, 2015/2016, or 2016/2017 Delivery Years to eliminate the capacity commitment shortfalls, across all of its Affected Resources, that result wholly and directly from the revised capability test procedures, and for which the Affected Resource Owner otherwise would be subject to Capacity Resource Deficiency Charges for the Delivery Year. In electing this option, the Affected Resource Owner relinquishes RPM Auction Credits associated with the reductions in Unforced Capacity commitments for all of its Affected Resources for the Delivery Year, and Locational Reliability Charges as described in Tariff, Attachment DD, section 5.14(e) of this Attachment DD are adjusted accordingly. Affected Resource Owners wishing to elect the Transition Mechanism for the 2015/2016 Delivery Year must notify the Office of the Interconnection by May 30, 2014. Affected Resource Owners wishing to elect the Transition Mechanism for the 2016/2017 Delivery Year must notify the Office of the Interconnection by July 25, 2014.

D. The Office of the Interconnection will offset the total reduction (across all Affected Resources and Affected Resource Owners) in Unforced Capacity commitments associated with the Transition Mechanism for the 2015/2016 and 2016/2017 Delivery Years by applying corresponding adjustments to the quantity of Buy Bid or Sell Offer activity in the upcoming Incremental Auctions for each of those Delivery Years, as described in Tariff, Attachment DD, sections 5.12(b)(ii) and 5.12(b)(iii).

E. By electing the Transition Mechanism, an Affected Resource Owner may receive relief from applicable Capacity Resource Deficiency Charges for the 2014/2015, 2015/2016, or 2016/2017 Delivery Years, and a Locational UCAP Seller that sells Locational UCAP based on an Affected Resource owned by the Affected Resource Owner may receive relief from applicable Capacity Resource Deficiency Charges for the 2014/2015 Delivery Year, to the extent

that the Affected Resource Owner demonstrates, to the satisfaction of the Office of the Interconnection, that an inability to deliver the amount of Unforced Capacity previously committed for the 2014/2015, 2015/2016, or 2016/2017 Delivery Years is due to a reduction in verified installed capacity available for sale as a direct result of revised generating unit capability verification test procedures effective with the summer 2014 capability tests, as set forth in the PJM Manuals; provided, however, that the Affected Resource Owner must provide the Office of the Interconnection with all information deemed necessary by the Office of the Interconnection to assess the merits of the request for relief.

#### **5.14C Demand Response Operational Resource Flexibility Transition Provision for RPM Delivery Years 2015/2016 and 2016/2017**

A. This transition provision applies only to Demand Resources for which a Curtailment Service Provider has existing RPM commitments for the 2015/2016 or 2016/2017 Delivery Years (alternatively referred to in this section 5.14C as “Applicable Delivery Years” and each an “Applicable Delivery Year”) that (i) cannot satisfy the 30-minute notification requirement as described in Tariff, Attachment DD-1, section A.2 and the parallel provision of RAA, Schedule 6; (ii) are not excepted from the 30-minute notification requirement as described in Tariff, Attachment DD-1, section A.2 and the parallel provision of RAA, Schedule 6; and (iii) cleared in the Base Residual Auction or First Incremental Auction for the 2015/2016 Delivery Year, or cleared in the Base Residual Auction for the 2016/2017 Delivery Year. A Demand Resource meeting these criteria and the Curtailment Service Provider of such a resource are hereafter in this section 5.14C referred to as an “Affected Demand Resource” and an “Affected Curtailment Service Provider,” respectively.

B. For this section 5.14C to apply to an Affected Demand Resource, the Affected Curtailment Service Provider must notify the Office of the Interconnection in writing, with regard to the following information by the applicable deadline:

- i) For each applicable Affected Demand Resource: the number of cleared megawatts of Unforced Capacity for the Applicable Delivery Year by end-use customer site that the Affected Curtailment Service Provider cannot deliver, calculated based on the most current information available to the Affected Curtailment Service Provider; the end-use customer name; electric distribution company’s account number for the end-use customer; address of end-use customer; type of Demand Resource (i.e., Limited DR, Annual DR, Extended Summer DR); the Zone or sub-Zone in which the end-use customer is located; and, a detailed description of why the end-use customer cannot comply with the 30-minute notification requirement or qualify for one of the exceptions to the 30-minute notification requirement provided in Tariff, Attachment DD-1 section A.2 and the parallel provision of RAA, Schedule 6.
- ii) If applicable, a detailed analysis that quantifies the amount of cleared megawatts of Unforced Capacity for the Applicable Delivery Year for prospective customer sales that could not be contracted by the Affected Curtailment Service Provider because of the 30-minute notification requirement provided in Tariff, Attachment DD-1, section A.2 and the parallel provisions of RAA, Schedule 6 that the Affected Curtailment Service

Provider cannot deliver, by type of Demand Resource (i.e. Limited DR, Annual DR, Extended Summer DR) and by Zone and sub-Zone, as applicable. The analysis should include the amount of Unforced Capacity expected from prospective customer sales for each Applicable Delivery Year and must include supporting detail to substantiate the difference in reduced sales expectations. The Affected Curtailment Service Provider should maintain records to support its analysis.

1. For the 2015/2016 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the Third Incremental Auction for the 2015/2016 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision may not sell or offer to sell megawatts in the modeled LDA or sub-LDA where an Affected Demand Resource is located in the Third Incremental Auction for the 2015/2016 Delivery Year.

2. For the 2016/2017 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the Second Incremental Auction for the 2016/2017 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision may not sell or offer to sell megawatts in the modeled LDA or sub-LDA where an Affected Demand Resource is located in the Second or Third Incremental Auctions for the 2016/2017 Delivery Year.

3. For the 2016/2017 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the Third Incremental Auction for the 2016/2017 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision must not have sold or offered to sell megawatts in the modeled LDA or sub-LDA where an Affected Demand Resource is located in the Second Incremental Auction for the 2016/2017 Delivery Year, and may not sell or offer to sell megawatts in the modeled LDA or sub-LDA where an Affected Demand Resource is located in the Third Incremental Auction for the 2016/2017 Delivery Year.

C. For the Third Incremental Auction for the 2015/2016 Delivery Year and the First, Second, and Third Incremental Auctions for the 2016/2017 Delivery Year, the Office of the Interconnection shall publish aggregate information on the undeliverable megawatts declared under this transition provision (hereafter, “non-viable megawatts”), by type of Demand Resource and by Zone or sub-Zone, concurrently with its posting of planning parameters for the applicable Scheduled Incremental Auction. Non-viable megawatts for a Scheduled Incremental Auction for an Applicable Delivery Year represent those megawatts meeting the criteria of subsection A above and declared in accordance with subsection B above. Prior to each Third Incremental Auction for an Applicable Delivery Year, the Office of the Interconnection shall apply adjustments equal to the declared non-viable megawatt quantity to the quantity of Buy Bid or Sell Offer activity in the upcoming Scheduled Incremental Auctions for the Applicable Delivery Year, as described in Tariff, Attachment DD, sections 5.12(b)(ii) and 5.12(b)(iii). Prior to the Second Incremental Auction for the 2016/2017 Delivery Year, the Office of the Interconnection shall adjust the recalculated PJM Region Reliability Requirement and recalculated LDA Reliability Requirements, as described in Tariff, Attachment DD, section 5.4(c), by the applicable quantity of declared non-viable megawatts, and shall update the PJM Region Reliability Requirement and each LDA Reliability Requirement for such Second Incremental

Auction only if the combined change of the applicable adjustment and applicable recalculation is greater than or equal to the lesser of (i) 500 megawatts or (ii) one percent of the prior PJM Region Reliability Requirement or one percent of the prior LDA Reliability Requirement, as applicable.

D. Prior to the start of each Applicable Delivery Year, the Office of the Interconnection shall reduce, by type of Demand Resource and by Zone or sub-Zone, the capacity commitment of each Affected Curtailment Service Provider that utilizes this transition provision for the Applicable Delivery Year based on the non-viable megawatts declared by the Affected Curtailment Service Provider under this transition provision. If the Affected Curtailment Service Provider cleared megawatts from multiple Affected Demand Resources of the same type and Zone or sub-Zone, or cleared megawatts in multiple RPM Auctions for the Applicable Delivery Year, the Office of the Interconnection shall allocate the reduction in capacity commitment by type of Demand Resource and by Zone or sub-Zone across the applicable Affected Demand Resources and relevant RPM Auctions. Such allocation shall be performed on a pro-rata basis, based on megawatts cleared by the Affected Demand Resources in the relevant RPM Auctions.

E. For each Applicable Delivery Year, an Affected Curtailment Service Provider that utilizes this transition provision for the Applicable Delivery Year relinquishes an Affected Demand Resource's RPM Auction Credits for the amount of capacity commitment reduction as determined under subsection D above. Locational Reliability Charges as described in Tariff, Attachment DD, section 5.14(e) are also adjusted accordingly.

#### **5.14D Capacity Performance and Base Capacity Transition Provision for RPM Delivery Years 2016/2017 and 2017/2018**

A. This transition provision applies only for procuring Capacity Performance Resources for the 2016/2017 and 2017/2018 Delivery Years.

B. For both the 2016/2017 and 2017/2018 Delivery Years, PJM will hold a Capacity Performance Transition Incremental Auction to procure Capacity Performance Resources.

1. For each Capacity Performance Transition Incremental Auction, the optimization algorithm shall consider:

- the target quantities of Capacity Performance Resources specified below;
- the Sell Offers submitted in such auction.

The Office of the Interconnection shall submit a Buy Bid based on the quantity of Capacity Performance Resources specified for that Delivery Year. For the 2016/2017 Delivery Year, the Office of the Interconnection shall submit a Buy Bid, at a price no higher than 0.5 times the Net CONE value for the PJM Region determined for the Base Residual Auction for that Delivery Year, for a quantity of Capacity Performance Resources equal to 60 percent of the updated Reliability Requirement for the PJM Region. For the 2017/2018 Delivery Year, the Office of the Interconnection shall submit a Buy Bid, at a price no higher than 0.6 times the Net CONE value for the PJM Region determined for the Base Residual Auction for that Delivery Year, for a

quantity of Capacity Performance Resources equal to 70 percent of the updated Reliability Requirement for the PJM Region.

2. For each Capacity Performance Transition Incremental Auction, the Office of the Interconnection shall calculate a clearing price to be paid for each megawatt-day of Unforced Capacity that clears in such auction. For the 2016/2017 Delivery Year, the Capacity Resource Clearing Price for any Capacity Performance Transition Incremental Auction shall not exceed 0.5 times the Net CONE value for the PJM Region determined for the Base Residual Auction for that Delivery Year. For the 2017/2018 Delivery Year, the Capacity Resource Clearing Price for any Capacity Performance Transition Incremental Auction shall not exceed 0.6 times the Net CONE value for the PJM Region determined for the Base Residual Auction for that Delivery Year.

3. A Capacity Market Seller may offer any Capacity Resource that has not been committed in an FRR Capacity Plan, that qualifies as a Capacity Performance Resource under Tariff, Attachment DD, section 5.5A(a) and that (i) has not cleared an RPM Auction for that Delivery Year; or (ii) has cleared in an RPM Auction for that Delivery Year. A Capacity Market Seller may offer an external Generation Capacity Resource to the extent that such resource: (i) is reasonably expected, by the relevant Delivery Year, to meet all applicable requirements to be treated as equivalent to PJM Region internal generation that is not subject to NERC tagging as an interchange transaction; (ii) has long-term firm transmission service confirmed on the complete transmission path from such resource into PJM; and (iii) is, by written commitment of the Capacity Market Seller, subject to the same obligations imposed on Generation Capacity Resources located in the PJM Region by Tariff, Attachment DD, section 6.6 to offer their capacity into RPM Auctions.

4. Capacity Resources that already cleared an RPM Auction for a Delivery Year, retain the capacity obligations for that Delivery Year, and clear in a Capacity Performance Transition Incremental Auction for the same Delivery Year shall: (i) receive a payment equal to the Capacity Resource Clearing Price as established in that Capacity Performance Transition Incremental Auction; and (ii) not be eligible to receive a payment for clearing in any prior RPM Auction for that Delivery Year.

D. All Capacity Performance Resources that clear in a Capacity Performance Transition Incremental Auction will be subject to the Non-Performance Charge set forth in Tariff, Attachment DD, section 10A.

#### **5.14E Demand Response Legacy Direct Load Control Transition Provision for RPM Delivery Years 2016/2017, 2017/2018, and 2018/2019**

A. This transition provision applies only to Demand Resources for which a Curtailment Service Provider has existing RPM commitments for the 2016/2017, 2017/2018, or 2018/2019 Delivery Years (alternatively referred to in this section 5.14E as “Applicable Delivery Years” and each an “Applicable Delivery Year”) that (i) qualified as Legacy Direct Load Control before June 1, 2016 as described in Tariff, Attachment DD-1, section G and the parallel provision of RAA, Schedule 6; (ii) cannot meet the requirements for using statistical sampling for residential non-interval metered customers as described in Tariff, Attachment DD-1, section K and the

parallel provision of RAA, Schedule 6; and (iii) cleared in the Base Residual Auction or First Incremental Auction for the 2016/2017 Delivery Year, cleared in the Base Residual Auction for the 2017/2018 Delivery Year, or cleared in the Base Residual Auction for the 2018/2019 Delivery Year. A Demand Resource meeting these criteria and the Curtailment Service Provider of such a resource are hereafter in this section 5.14E referred to as an “Affected Demand Resource” and an “Affected Curtailment Service Provider,” respectively.

B. For this section 5.14E to apply to an Affected Demand Resource, the Affected Curtailment Service Provider must notify the Office of the Interconnection in writing, with regard to the following information, by the applicable deadline:

- i) For each applicable Affected Demand Resource: the number of cleared megawatts of Unforced Capacity for the Applicable Delivery Year by end-use customer site that the Affected Curtailment Service Provider cannot deliver, calculated based on the most current information available to the Affected Curtailment Service Provider; electric distribution company’s account number for the end-use customer; address of end-use customer; type of Demand Resource (i.e., Limited DR, Annual DR, Extended Summer DR); the Zone or sub-Zone in which the end-use customer is located; and, a detailed description of why the end-use customer cannot comply with statistical sampling for residential non-interval metered customers requirement as described in Tariff, Attachment DD-1, section K and the parallel provision of RAA, Schedule 6.
- ii) If applicable, a detailed analysis that quantifies the amount of cleared megawatts of Unforced Capacity for the Applicable Delivery Year for prospective customer sales that could not be contracted by the Affected Curtailment Service Provider because of the statistical sampling for residential non-interval metered customers requirement as described in Tariff, Attachment DD-1, section K and the parallel provision of RAA, Schedule 6 that the Affected Curtailment Service Provider cannot deliver, by type of Demand Resource (i.e. Limited DR, Annual DR, Extended Summer DR) and by Zone and sub-Zone, as applicable. The analysis should include the amount of Unforced Capacity expected from prospective customer sales for each Applicable Delivery Year and must include supporting detail to substantiate the difference in reduced sales expectations. The Affected Curtailment Service Provider should maintain records to support its analysis.

1. For the 2016/2017 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the Second and/or Third Incremental Auction for the 2016/2017 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision may not sell or offer to sell megawatts in the matching LDA or sub-LDA where an Affected Demand Resource is located in the Second or Third Incremental Auction for the 2016/2017 Delivery Year.

2. For the 2017/2018 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the First, Second and/or Third Incremental Auction for the 2017/2018 Delivery Year. Such

Affected Curtailment Service Provider that utilizes this transition provision may not sell or offer to sell megawatts in the matching LDA or sub-LDA where an Affected Demand Resource is located in the First, Second or Third Incremental Auctions for the 2017/2018 Delivery Year.

3. For the 2018/2019 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the First, Second and/or Third Incremental Auction for the 2018/2019 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision may not sell or offer to sell megawatts in the matching LDA or sub-LDA where an Affected Demand Resource is located in the First, Second or Third Incremental Auctions for the 2018/2019 Delivery Year.

C. For the Second and Third Incremental Auction for the 2016/2017 Delivery Year, the First, Second, and Third Incremental Auctions for the 2017/2018 Delivery Year, and the First, Second, and Third Incremental Auctions for the 2018/2019 Delivery Year, the Office of the Interconnection shall publish aggregate information on the undeliverable megawatts declared under this transition provision (hereafter, “non-viable megawatts”), by type of Demand Resource and by Zone or sub-Zone, concurrently with its posting of planning parameters for the applicable Scheduled Incremental Auction. Non-viable megawatts for a Scheduled Incremental Auction for an Applicable Delivery Year represent those megawatts meeting the criteria of subsection A above and declared in accordance with subsection B above. Prior to each Scheduled Incremental Auction for an Applicable Delivery Year, the Office of the Interconnection shall apply adjustments equal to the declared non-viable megawatt quantity to the quantity of Buy Bid or Sell Offer activity in the upcoming Scheduled Incremental Auctions for the Applicable Delivery Year, as described in Tariff, Attachment DD, sections 5.12(b)(ii) and 5.12(b)(iii). Prior to the Second Incremental Auction for the 2016/2017 Delivery Year, the First and Second Incremental Auction for the 2017/2018 Delivery Year, and the First and Second Incremental Auction for the 2018/2019 Delivery Year, the Office of the Interconnection shall adjust the recalculated PJM Region Reliability Requirement and recalculated LDA Reliability Requirements, as described in Tariff, Attachment DD, section 5.4(c), by the applicable quantity of declared non-viable megawatts, and shall update the PJM Region Reliability Requirement and each LDA Reliability Requirement for such Incremental Auction only if the combined change of the applicable adjustment and applicable recalculation is greater than or equal to the lesser of (i) 500 megawatts or (ii) one percent of the prior PJM Region Reliability Requirement or one percent of the prior LDA Reliability Requirement, as applicable.

D. Prior to the start of each Applicable Delivery Year, the Office of the Interconnection shall reduce, by type of Demand Resource and by Zone or sub-Zone, the capacity commitment of each Affected Curtailment Service Provider that utilizes this transition provision for the Applicable Delivery Year based on the non-viable megawatts declared by the Affected Curtailment Service Provider under this transition provision. If the Affected Curtailment Service Provider cleared megawatts from multiple Affected Demand Resources of the same type and Zone or sub-Zone, or cleared MWs in multiple RPM Auctions for the Applicable Delivery Year, the Office of the Interconnection shall allocate the reduction in capacity commitment by type of Demand Resource and by Zone or sub-Zone across the applicable Affected Demand Resources and relevant RPM Auctions. Such allocation shall be performed on a pro-rata basis, based on megawatts cleared by the Affected Demand Resources in the relevant RPM Auctions.



E. For each Applicable Delivery Year, an Affected Curtailment Service Provider that utilizes this transition provision for the Applicable Delivery Year relinquishes an Affected Demand Resource's RPM Auction credits for the amount of capacity commitment reduction as determined under subsection D above. Locational Reliability Charges as described in Tariff, Attachment DD, section 5.14(e) are also adjusted accordingly.

**ATTACHMENT DD-3**

State policies or programs accepted as Conditioned State Support and subject to the Minimum Offer Price Rule, specified in Tariff, Attachment DD, section 5.14(h-2), are as follows:

[reserved]

# Attachment C

Affidavit of Peter Cramton  
on behalf of PJM Interconnection, L.L.C.



Wilson of Stanford University, recommended that ISO New England eliminate their proposed capacity market until flaws could be fixed (Cramton and Wilson 1998). Subsequent research described the deficiencies of early capacity markets (Cramton 2003) and how to fix them (Cramton and Stoft 2006; Cramton et al. 2013).

6. The critical elements of a modern capacity market are the forward procurement, typically three years in advance, of capacity consistent with an administrative demand curve, representing consumers' preference for reliability. The connection between the demand curve and reliability is seen when one considers the impact of shifting the demand curve to the right so that at every price more quantity is demanded. The shift brings more capacity to the market, and the additional resources make it more likely that the market will avoid shortage. The demand curve reflects the marginal value of resources in avoiding shortage. The capacity product is both a physical capability and financial obligation to provide energy during shortages. The financial obligation provides strong performance incentives. The system operator settles any deviation from the supplier's load-following responsibility at the administrative shortage price—the value of lost load. The current PJM capacity market is consistent with this framework.
7. From January 2020 to the present, together with my colleagues, Emmanuele Bobbio at the University of Cologne, David Malec at the University of Maryland, and Pat Sujarittanonta at Chulalongkorn University, I developed a multi-decade model of the energy transition in PJM (Cramton et al. 2021). The research was supported by PJM, the University of Cologne, the University of Maryland, the German Research Foundation (DFG), and the European Research Council (ERC). The model allows researchers to study the market impacts of alternative market rules and policies. Each year, investors decide which resources enter and exit, given forward-looking consistent expectations about energy profits, prices, and costs. The model is unique in modeling investment decisions at the individual unit level based on precisely calculated profits from energy, reserves, and capacity markets. These profits depend critically on the resource structure, which changes each year with investor decisions. New and essential elements of electricity markets, such as battery storage, are fully integrated. The model provides insights into how market rules and policies impact market outcomes, including reliability and cost. My analysis of PJM's MOPR proposal is informed from this model.
8. I begin with some background on MOPR and its role in capacity markets and electricity markets generally. MOPR attempts to mitigate the exercise of buyer market power in capacity markets. I then analyze PJM's MOPR proposal. I compare the likely market impact of the broad MOPR articulated in the December 2019 order of the Federal Energy Regulatory Commission (FERC) and PJM's current MOPR proposal. I refer to these two approaches as broad MOPR (FERC 2019) and narrow MOPR (PJM 2021a,b).
9. In my view, PJM's narrow MOPR is an essential improvement over the broad MOPR.
10. The broad MOPR casts too wide a net. It has a broad definition of subsidized resources—virtually any new resource procured or supported by the state—and mandates a minimum offer price for these resources. The rule could potentially keep an active energy resource from receiving capacity revenue indefinitely. These excluded resources are contributing to

reliability yet are ignored in the capacity market. The result is consumers buying more capacity than is consistent with their preference for reliability as expressed in the capacity demand curve.

11. Moreover, these extra resources will reduce spot market prices and thereby amplify the missing money problem. As more state-sponsored resources enter the market, this creates counter-productive feedback. The reserve margin increases, yet capacity prices rise due to more excluded resources, and spot prices fall. The capacity price no longer reflects the cost of supplying energy during shortage.
12. By contrast, the narrow MOPR acknowledges the state's role in policy. The minimum offer price rule is triggered only when there is reason to suspect a resource's offer is an exercise of buyer market power or its state support depends on clearing in the capacity market. Active energy resources are only excluded from the capacity market in response to identified conditional state support or buyer market power. The rule's clarity will likely discourage such misconduct, thus leading to the preferred outcome of deterring such attempts instead of mitigating the effort via administratively determined offer price revisions that may fail to clear. Under this approach, therefore, there will likely be few resources excluded in equilibrium. PJM's approach also eliminates the broad MOPR's disconnect between the capacity resources and those providing reliability. Ideally, the capacity market is a financial derivative of the real-time energy market. The capacity price primarily reflects the financial cost of the reliability obligation.
13. The design of the minimum offer price rule must weigh two types of errors. Too broad of a rule excludes some new resources from receiving capacity revenues; too narrow of a rule could drive premature exit of economic resources or could permit noneconomic new entry. To me, the broad rule is riskier.
14. The integrity of the capacity market is better served with the narrow MOPR. The narrow MOPR protects against buyer market power without presuming that states' specific support for their resource preferences, in and of themselves, represents an abuse of buyer market power. The narrow MOPR presumes sellers are not submitting improperly low-priced offers but includes protections, allowing PJM and the independent market monitor to identify the exercise of buyer market power and apply the MOPR. The rule enables PJM to bring to FERC instances of conditioned state support and PJM's proposed MOPR mitigation in such a case, which PJM would implement with FERC approval.
15. My conclusion is reinforced when one recognizes the long-run implications of the broad MOPR. When the minimum offer price excludes some energy resources from capacity revenues, the practical result is available supply, supporting reliability, exceeds the reserve level cleared in the capacity auction. This shifts revenues from the energy and reserves markets to the capacity market, increasing the role of the capacity revenues in investment decisions. This result moves the market further from the ideal where the capacity revenues reflect the financial cost of the obligation to deliver energy and reserves during shortages.
16. Identifying inappropriate conditional state support and mitigating buyer market power remains important, and the narrow MOPR retains these protections. My point is that the

broad MOPR goes too far and would do more harm than good. The risk is significant that the broad MOPR will bring too many resources to PJM by paying a capacity price greater than the consumers' preference for reliability.

17. The narrow MOPR addresses market power abuse without interfering with price formation and efficient entry and exit. The narrow MOPR respects the states' resource preferences and better supports an effective energy transition.
18. From an economic perspective, the first-best policy would include the marginal social cost of each pollution externality in the electricity price. Regulators can achieve that first-best policy only with an effective national policy. The social cost of carbon would be best established and imposed at the federal level since it is a global pollutant. Even local pollutants like nitrogen oxides, sulfur dioxide, and particulates cross state borders, so national pricing of these pollutants is efficient. Absent federal leadership, states have intervened with policies that reflect state preferences. Although a coherent national policy would provide the best approach, the narrow MOPR would better accommodate states' preferences until a good federal policy arrives.

## **Background**

19. The MOPR is a feature of the capacity market. However, it is helpful to start with the spot market for energy and reserves, consisting of a day-ahead market for scheduling and a real-time market for dispatch. The spot market is the backbone of restructured electricity markets.

### ***The spot market for energy and reserves***

20. In theory, an electricity market can provide ideal investment incentives with an efficient spot market that accepts demand bids and supply offers for energy and reserves. The system operator takes these bids and offers and finds the day-ahead schedule of resources and real-time dispatch that maximizes as-bid social welfare subject to resource and grid constraints. PJM uses the day-ahead and real-time prices in this optimization to maximize welfare and keep supply and demand balanced.
21. One challenge with this approach is a limited response of the demand side to price. Most consumers neither see nor feel the real-time price. As a result, there is too little reduction in demand as prices rise. In times of limited supply, this may make it difficult or impossible for the system operator to balance the system. Shortages can and do occur.
22. The possibility of shortage creates a problem for the market. What should the price be in circumstances where no price can balance supply and demand? The answer is that the regulator must specify an administrative shortage price that reflects the value of lost load. The shortage price represents consumers' preference for reliability in a world without robust demand response. The higher the shortage price, the stronger the incentive to invest in resources that perform well during shortages and a lower risk of shedding load.
23. There are practical benefits from making the performance incentive smooth as the system moves near shortage. Continuity is achieved with reserve demand curves that increase

steeply to the value of lost load as reserve quantities fall to the point where the system operator must start shedding load (Hogan 2013). In this way, the reserve demand curves cause prices to escalate quickly to the value of lost load as the market moves from near-shortage to shedding load. PJM recently adopted, and FERC approved, this best practice in their spot market for implementation on May 1, 2022.

24. One implication of adding reserve demand curves to the spot market is that, when correctly set, they restore missing money. With the demand curves administratively set to reflect consumers' preference for reliability, the spot market yields prices sufficient to motivate efficient investment despite the absence of robust demand response. Some markets, such as ERCOT, stop at this point—the so-called energy-only market.

### ***Capacity market***

25. Some markets, such as PJM, NY ISO, and ISO New England, include a capacity market. Absent reserve demand curves, a capacity market is necessary to restore missing money. But even when the day-ahead and real-time markets have reserve demand curves, a well-designed capacity market can play a role, helping to bring adequate resources, coordinate investment, and manage risk.
26. Like the reserve demand curves, the capacity market is an administrative construct. But while the reserve demand curves directly address an energy market's imperfect shortage pricing, a capacity market is indirect. Indeed, a capacity market that succeeds in bringing about adequate resources may even blunt the incentive for energy market reforms.

### ***Capacity demand curve***

27. A critical feature of the capacity market is the capacity demand curve—known as the variable resource requirement curve in PJM. The demand curve specifies the quantity of capacity procured as a function of the capacity price. The demand curve is centered at the target capacity level when the price is net cost of new entry (CONE), the cost of new entry for a benchmark resource less the expected revenues earned in the spot market. For prices above net CONE, less capacity is purchased; for prices below net CONE, more capacity is purchased. This price response is consistent with the consumers' demand for reliability. When reliability is more expensive, customers buy less of it. Like all demand curves, the capacity demand curve reflects the incremental value of the capacity resource. As additional capacity is added, its marginal value falls.

### ***Price formation***

28. Early capacity markets had a vertical demand curve at the target level of capacity. Vertical demand created a boom-bust tendency where the capacity price would oscillate between floor and ceiling prices or persist at the floor price even if capacity only minimally exceeded the target level. This approach sent a poor price signal that did not reflect the incremental value of capacity.
29. More commonly today, capacity markets have a downward-sloping demand curve that better reflects the marginal value and reduces price volatility. The sloped demand curve provides a smooth response to changes in quantity, consistent with the reliability benefit the marginal resource brings. As additional resources are added to the market, the capacity



price falls since the resource's marginal reliability contribution is less when more resources are in the market. Similarly, as resources are removed from the market, the capacity price increases, reflecting the higher reliability contribution in a tighter market. This price response is the purpose of the capacity demand curve and the essence of price formation.

30. A downward-sloping demand curve also weakens the incentive to exercise market power. With the vertical demand curve, the sellers could reduce supply so that the capacity price would be equal to the price ceiling. Similarly, the vertical demand curve creates incentives for the buyer to expand supply to push the capacity price to the price floor. The sloped demand curve mitigates both incentives. Changes in supply have a more modest impact on the capacity price under the sloped curve than they would with the vertical curve.

### ***Mitigating market power***

31. Even with a sloped demand curve, the exercise of market power remains a concern. In every electricity market, there are some suppliers of significant size. These suppliers can exercise market power by withholding only a small fraction of their capacity. Whether they have an incentive to do so is another matter. The price impact may not be large, and competitors' capacity at least partially replaces their withheld capacity. The supplier might enjoy that higher capacity price only for a single year yet faces greater competition in future years in the capacity, energy, and reserves markets.
32. All capacity markets have protections to mitigate supplier market power. Typically, these measures restrict how high incumbent capacity can offer in the capacity market. It is large incumbents that have the most to gain from the exercise of market power.
33. The focus on supplier market power is natural since the buyer is obligated to purchase. However, buyers can impact the capacity price through the competitive procurement of additional resources and then offer those resources in the capacity market at low prices. Some utilities that serve load are not suited to benefit from the exercise of buyer market power. For example, a utility with a division that owns generation may have supply resources and pass on capacity costs to consumers. However, states, cooperatives, and other large buyers may have an interest in reducing capacity prices. MOPR is intended to mitigate the adverse impact of the exercise of buyer market power.

### ***The minimum offer price rule***

34. The minimum offer price rule prevents some state-sponsored resources from offering below a minimum offer price. The minimum offer price depends on whether the resource is new or existing. New resources are defined as those that have never cleared in the capacity market. The minimum offer price for new resources is much higher than that for existing resources to reflect the higher cost of a new resource. The rule is intended to mitigate the exercise of buyer market power. In some state procurements of resources, the payment of the competitive procurement price was made conditional on the resource clearing in the capacity market. This conditional support may force some noneconomic resources to stay in the capacity auction regardless of price, thereby causing the capacity price to fall.

35. In December 2019, after reviewing PJM's filing to expand MOPR, FERC went further and ordered a significant expansion of MOPR—a broad MOPR covering a large set of state actions. The broad MOPR finds specific business models such as public power to be a subsidy that could trigger MOPR going forward. The broad MOPR extends the minimum offer price rule to virtually all state-sponsored resources. These resources would be required to offer at least the minimum offer price unless granted an exception based on PJM's and the independent market monitor's review of the resource's specific costs and revenues.
36. Some argue that the broad MOPR is appropriate because state actions to address resource externalities result in some resources receiving extra compensation. They claim this may unjustly reduce the capacity price and undermine the competitive entry of new resources.
37. I disagree. Even if one assumed that state programs directing additional funds to resources based on environmental or other favored attributes could exert downward pressure on capacity prices, the broad MOPR's efforts to reverse that situation would worsen matters. By clearing resources that duplicate resources favored by state policy, the broad MOPR results in downward pressure on energy prices, the largest source of resource revenues. The broad MOPR also increases the capacity price, slows the energy transition, and disrespects states' policy preferences.

### **PJM's MOPR Proposal**

38. The PJM MOPR proposal prohibits the exercise of buyer market power. It mitigates the exercise of market power and provides vehicles for parties to bring matters to FERC for final resolution. The approach is simple and transparent. It begins with a clear definition of buyer market power and its exercise.
39. Buyer market power is the ability of a market participant with a load interest to suppress market-clearing prices for the overall benefit of the participant's portfolio. The exercise of buyer market power requires both the ability and incentive to materially reduce capacity clearing prices by offering capacity or directing another to offer capacity below cost.
40. Conditioned state support is clearly defined as out-of-market payments in exchange for the sale of a FERC-jurisdictional product conditioned on clearing in any PJM capacity market.
41. Market participants must certify whether they have received conditioned state support and whether they intend to offer their resources to exercise buyer market power. PJM and the independent market monitor examine the certifications to confirm that they appear correct. Where PJM, or the independent market monitor, has reason to doubt the certification of a lack of buyer market power, PJM can require the seller to provide further information. If concerns remain, PJM can require the seller to offer no lower than the minimum offer price as defined by MOPR. In instances where PJM, aided by the independent market monitor, identifies conditioned state support, PJM can seek FERC approval to require the seller to offer no lower than the minimum offer price.
42. Market participants that do not receive conditional state support and do not exercise buyer market power can offer below the minimum offer price.

43. The minimum offer price differs between new and existing units. New units—resources that have never cleared in a capacity auction—cannot offer below the cost of new entry less estimated revenues. Existing units—resources that have cleared in a prior capacity auction—cannot offer below the resource’s net going forward cost.
44. The narrow MOPR identifies those instances of either conditional state support or the exercise of buyer market power and then applies the appropriate minimum offer price. The approach is narrowly tailored to circumstances. Circumstances are identified either by the market participant or by PJM or the independent market monitor with review by FERC.

### **Market Impact of Broad MOPR vs. Narrow MOPR**

45. To evaluate the market impact of the alternative MOPR approaches, I study entry and exit in PJM from 2019 to 2040 using the model described in Cramton et al. (2021). The model has been carefully calibrated based on the resources in PJM as of 2019. The model examines the equilibrium entry and exit of resources on an annual basis. The model estimates resource revenues from the capacity, energy, and reserves markets to determine the net present value of entry or exit. I model PJM’s day-ahead and real-time markets to form these estimates. The expectations are roughly consistent; that is, the realization of cash flows over the life of the resource are approximately equal to the estimates. The investors do a good job of anticipating the future and therefore do not regret the decisions made. Each year profitable resources enter, and unprofitable resources exit, as coordinated by the capacity market conducted three years ahead.
46. Battery storage is fully integrated in the model. The battery resources are optimally scheduled and dispatched to maximize profits. For simplicity, only two-hour batteries are considered.
47. Climate policy is modeled with a carbon price. Investors in long-lived energy projects have an internal carbon price used in decision-making. A carbon price is the most coherent way to model climate policy. I employ a modest carbon price of \$2/ton in 2019, which increases by \$3/ton each year. In 2020, the implicit carbon price is \$5/ton; in 2040, the carbon price is \$65/ton.
48. As described in Cramton et al. (2021), the modeling requires extensive computation. The modeling was done on 22 computational servers running 24x7 for many months, creating an extensive database of market outcomes at the 5-minute level as a function of the resource structure and other parameters. Once the database of market outcomes is built, I can run the model much more quickly to analyze, for example, possible market rule changes. To correctly compute net present values for long-lived assets, the analysis extends into 2100. I only report results through 2040.
49. PJM has proposed endogenous capacity values based on resources’ effective load carrying capability (ELCC). Given the forward-looking nature of our modeling, the model assumes endogenous capacity values as in the ELCC approach.

50. I consider two scenarios:

Narrow MOPR—This scenario fits the narrow MOPR proposed by PJM. As applied here, the model assumes the clear, narrowly targeted rule is effective and deters both the exercise of buyer market power and attempts at conditioned state support. The model thus assumes that resources do not receive conditional state support and do not exercise buyer market power.

Broad MOPR—This is the broad MOPR scenario established by FERC’s December 2019 Order. The minimum offer price applies to all renewable resources.

51. Thus far, I have argued from logic that the broad MOPR may lead to excessive resources in PJM and higher costs to consumers. The logic does not determine the magnitude of these impacts. This is where the simulation adds value. It can test the logic and estimate the magnitude of the differences between policy choices.

52. There are two main hypotheses.

Hypothesis 1: The PJM market is reliable with either a broad or narrow MOPR.

Hypothesis 2: The broad MOPR brings more resources to PJM. However, these extra resources do not make the market more reliable.

53. As with any simulation of this complexity, I have made many assumptions. See Cramton et al. (2021) for details. Calibration of the model is imperfect. Miscalibration is especially apt to impact absolute results, such as price levels. It is less prone to affect relative results, such as comparison between scenarios. Thus, the reader should focus primarily on the differences between the broad and narrow MOPR scenarios.

54. I now discuss the results from the analysis of these two scenarios. The figures are at the end of this document.

### ***Resource mix and entry and exit***

55. Resources enter and exit the market on an annual basis. Some resources exit because they reach the end of life. Others exit because profits going forward turn negative. New resources enter based on forward-looking profit expectations.

56. Figure 1 shows how the energy mix evolves from 2019 to 2040. Given the modest carbon price, thermal resources continue to play an important role. Coal gradually exits, as do the legacy gas resources. These resources are replaced with storage, wind, and solar. Combined cycle with carbon capture does not enter until about 2035. The differences between the broad MOPR and narrow MOPR cases are modest.

57. Figure 2 shows the annual net entries (entries minus exits) in GWs averaged over 2019-2040. Over the next two decades, the model predicts that coal, legacy gas, and combustion turbines will be replaced with solar, wind, storage, and combined cycle gas (with carbon capture in the later years). Combined cycle units remain a critical component in the mix

and increases, offsetting the reduction in combustion turbines. These portfolio changes over the next twenty years are similar under the narrow and broad MOPR scenarios.

58. Figure 3 shows the detail of entry and exit by year.

### ***Capacity prices and reserve margin***

59. Figure 4 shows capacity prices and reserve margins by year. Interestingly, MOPR has little impact on capacity prices. There is no evidence of “price suppression” with narrow MOPR.
60. By contrast, the broad MOPR results in a higher reserve margin—about two percentage points higher in most years. The reserve margins may seem low. This is because a unit’s capacity is defined as its nameplate capacity times its capacity value. Capacity values can change substantially based on performance. For example, a long period of little wind and high demand can cause a significant drop in wind capacity values. After such an event, the same set of resources has a lower reserve margin. The reader should interpret reserve margins relatively, as I do so here.
61. The main implication of broad MOPR is not to raise the capacity price. Instead, broad MOPR brings in some extra resources without letting the capacity price decrease. The main result is a higher reserve margin. The additional resources might be desirable if they improved reliability; however, we will find they do not.

### ***Energy and reserves prices and reliability***

62. Figure 5 shows the average annual prices for energy and reserves by year. Energy prices are similar in the broad MOPR and narrow MOPR cases. Reserve prices are also similar in narrow and broad MOPR scenarios.
63. Figure 6 shows price duration curves by decade. The broad MOPR and narrow MOPR cases again are similar. Note that Figure 6 also indicates that load is reliably served in all cases. Shortage rarely occurs. To better see this fact, Figure 7 zooms in to the right tail of the duration curves, showing 99.5% and above. Narrow MOPR does have a slightly higher incidence of high prices in both day-ahead and real-time markets. Shortage never occurs day-ahead and is extremely rare in real-time. This demonstrates the robustness of the capacity market to make sure there are sufficient resources to serve load. As most relevant to the present topic, a broad MOPR is not needed to preserve the long-term reliability of service to load.
64. Figure 8 shows the frequency of price spikes—five-minute intervals with prices more than \$100/MWh. The price spikes are similar in narrow and broad MOPR cases. Regardless of the MOPR choice, as the share of renewables grows, price spikes become more frequent, and real-time price spikes are more frequent and more extreme than day-ahead price spikes. Figure 9 zooms in to see the frequency of prices more than \$400/MWh. The conclusion is the same. Price spikes primarily occur in real-time and grow in frequency with higher renewable penetration. Interestingly, the frequency of extreme price spikes above \$1600/MWh does not increase as renewable resources are added. Batteries step in to provide the flexibility required with more renewable resources.

### ***Components of the electricity price***

65. Figure 10 shows the electricity price components by year. I split energy into base energy when the energy price is less than \$200/MWh and peak energy when the energy price is more than \$200/MWh. The main components of price are capacity and base energy. Uplift, reserves, and peak energy are much less significant. The broad MOPR and narrow MOPR cases are similar.
66. Figure 11 shows the electricity cost components by year. The all-in price consists of capital costs, operating costs, generation costs, and profits. Profits are initially negative due to excessive resources. Once the surplus resources exit, profits return and are maintained through 2040. The broad MOPR and narrow MOPR cases are similar, although there is a drop in profits and all-in cost for the broad MOPR case toward the end of the analysis period.

### ***Supplementary figures***

67. Figure 12 shows the average performance of resources by decade in the five-minute intervals used to measure performance. These are five-minute intervals with a real-time price of at least \$200/MWh. I used fixed capacity values for thermal resources since this simple approach is apt to be more consistent with the ELCC method. For renewable resources and storage, capacity values are calculated using exponential smoothing. The broad MOPR and narrow MOPR cases show very similar performance results by resource type.
68. Figure 13 shows the average annual net entries by decade.
69. The entry and exits are determined based on consistent expectations of going forward profits, summarized in a net present value calculation. The net present value of incumbent resources is shown in Figure 14. Figure 15 shows the net present value for new entrants. The narrow MOPR and broad MOPR cases are again similar. The broad MOPR slightly harms solar and wind in the early years.
70. Figure 16 shows the profit breakdown by year.
71. The model uses an econometric proxy model to determine profits as a function of resource structure and other parameters. To check the quality of the proxy model, I ran the energy market model for each year along the equilibrium path. Figure 17 shows the difference between the energy proxy results and the results computed from the energy market model along the equilibrium path by decade. The profit difference is relative to the annualized gross cost of entry for the resource in 2019. Profit differences are negligible in 2019. For the 2020s and 2030s, profit differences are small relative to the cost of energy. Performance differences are more prominent.
72. The quality of the results can be improved with additional computation and improvement of the proxy model. However, I believe the results are sufficient for my conclusions.

## **Conclusion**

73. Both logic and analysis lead me to conclude that PJM’s proposed MOPR is an essential improvement. The PJM rule is narrowly tailored to address buyer market power. By contrast, the current rule is too broad. It imposes a minimum offer price in circumstances where such intervention is unwarranted. The cost of the broad MOPR stems primarily from having some resources that provide reliability excluded from the capacity market. This exclusion causes the capacity price to clear too high and not correctly reflect the marginal value of reliability to consumers expressed by the capacity demand curve.
74. My analysis of entry and exit in PJM over the next two decades confirms this conclusion. Although both the broad MOPR and narrow MOPR bring reliability, the broad MOPR results in more resources and more expense for consumers. The difference is not dramatic. The main reason for the modest impact is little change in the resource schedule and dispatch. Energy and reserves prices stay about the same. Capacity prices are also about the same because the broad MOPR prevents the extra resources from reducing the capacity price. Thus, the advantage of narrow MOPR is reduced consumer cost. Narrow MOPR avoids carrying additional resources that do not contribute to reliability.

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Figure 1: Energy mix by year, 2019-2040

(1) Effects on net entries	(2) Effects on energy mix	(3) Incumbent NPV	(4) New entrant NPV
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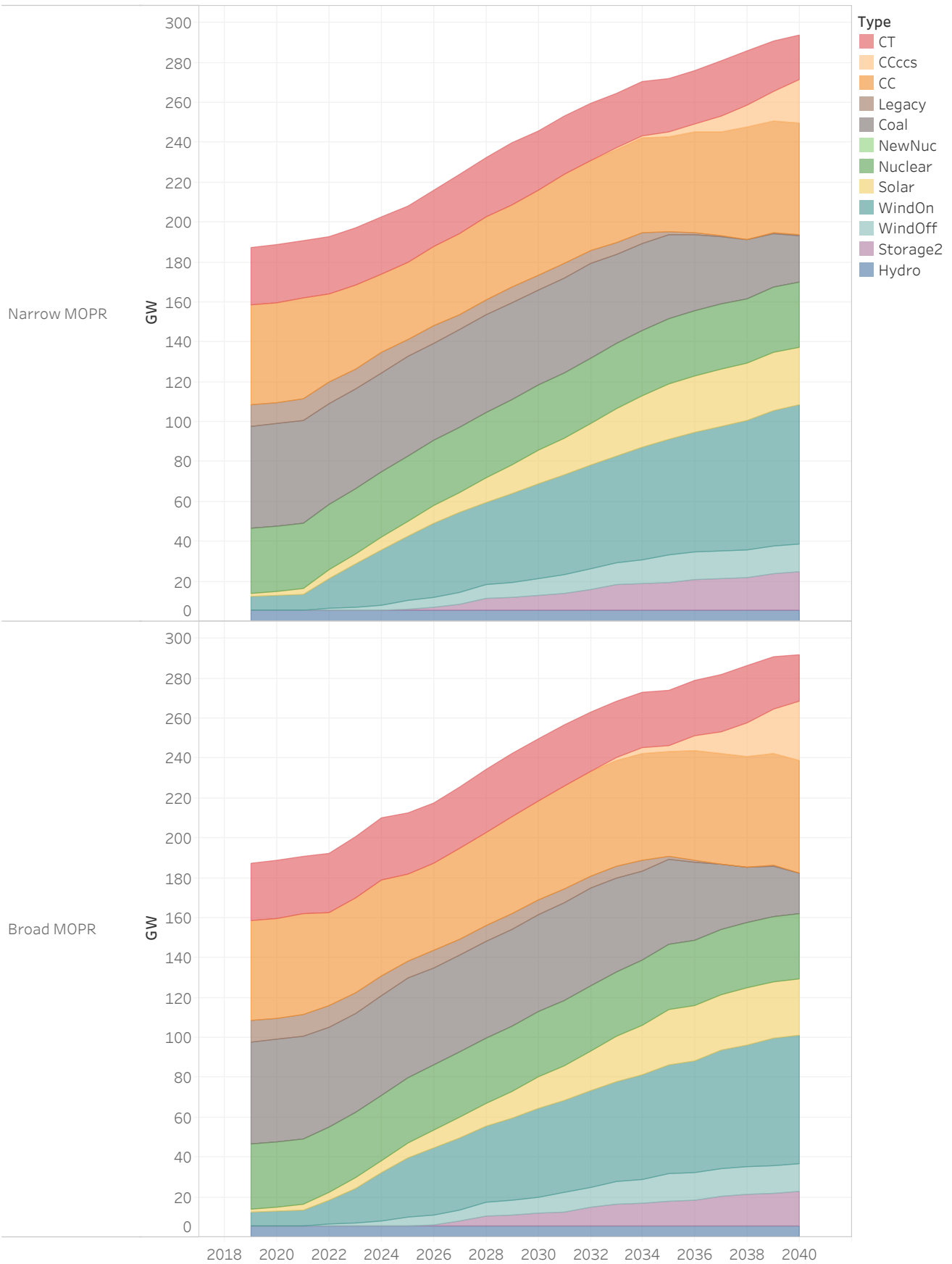




Figure 2: Average annual net entries, 2019-2040

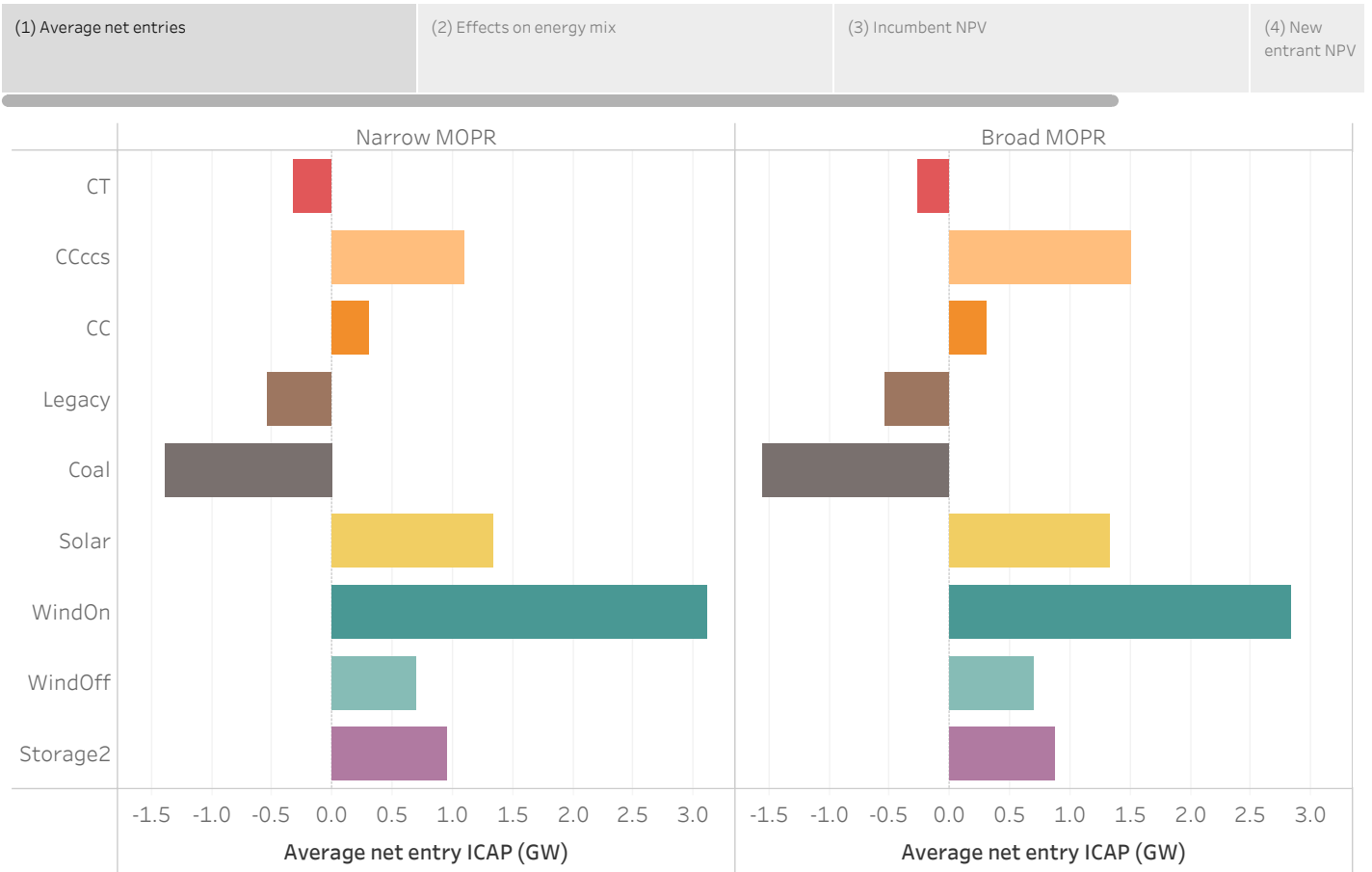


Figure 3: Entry and exit by year, 2019-2040

Entry & exit detail

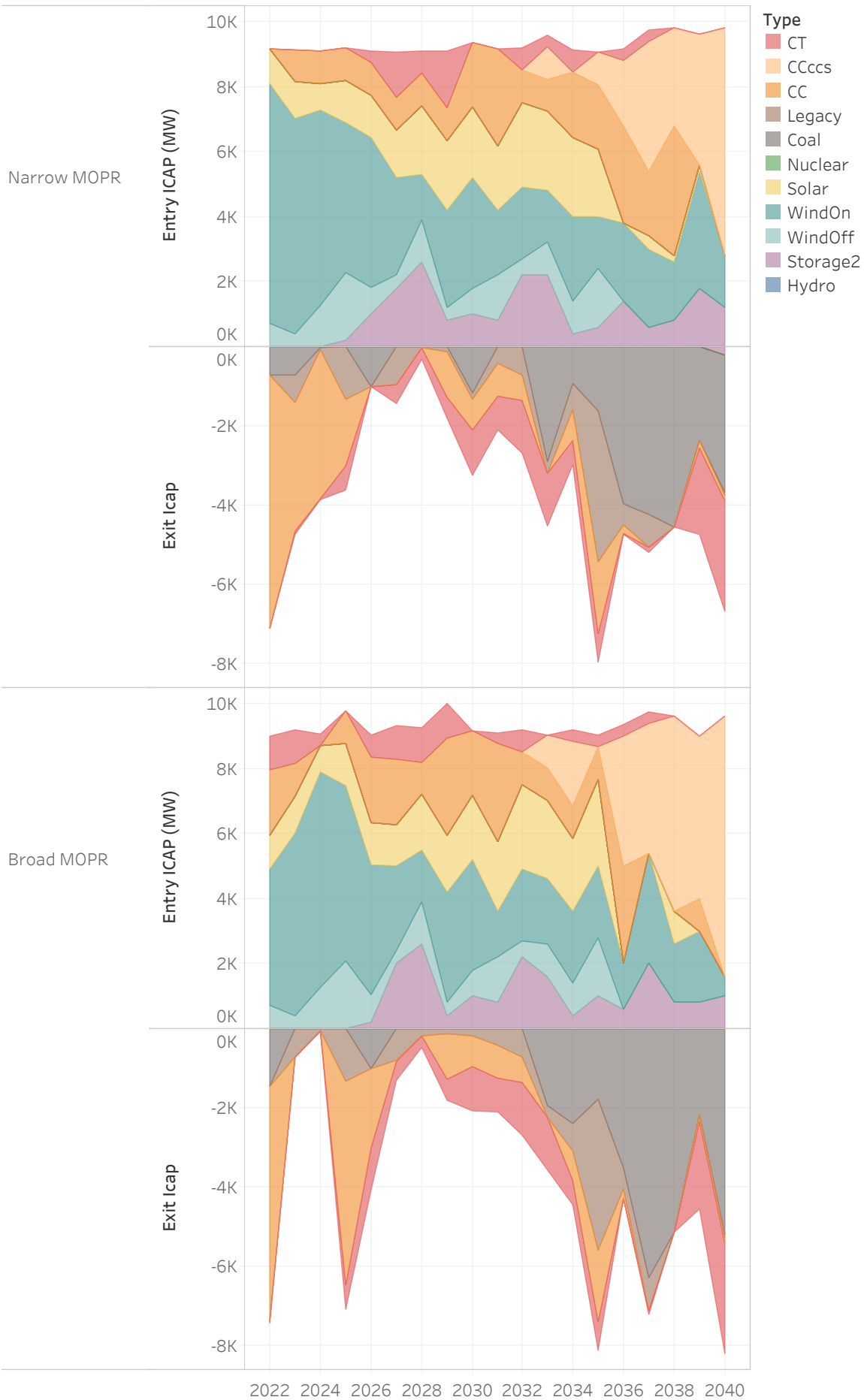


Figure 4: Capacity price and reserve margin by year, 2019-2040

Capacity price and reserve margin (capacity is defined as nameplate times capacity value)



Figure 5: Generation and reserve prices by year, 2019-2040

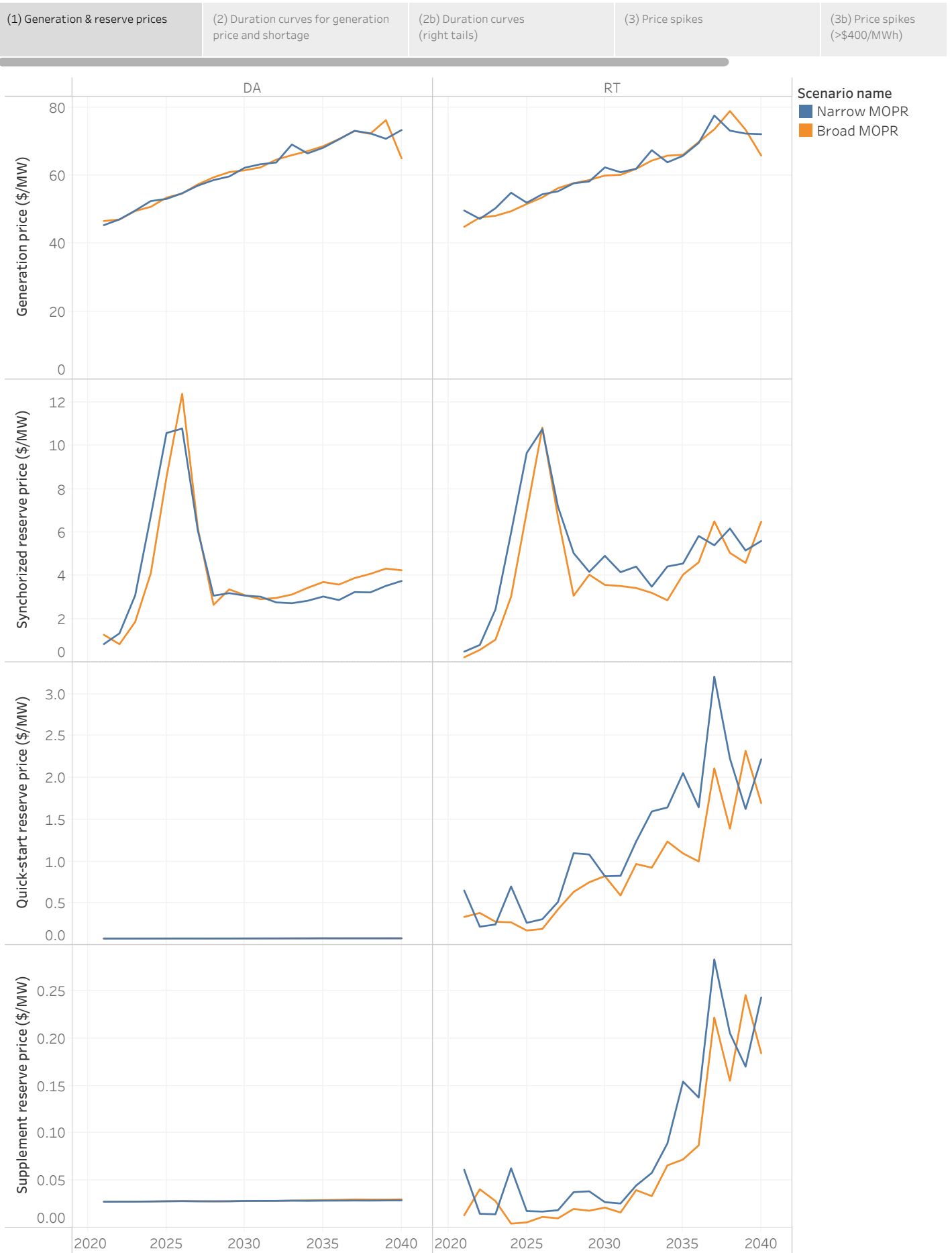


Figure 6: Duration curves for generation price and shortage by decade

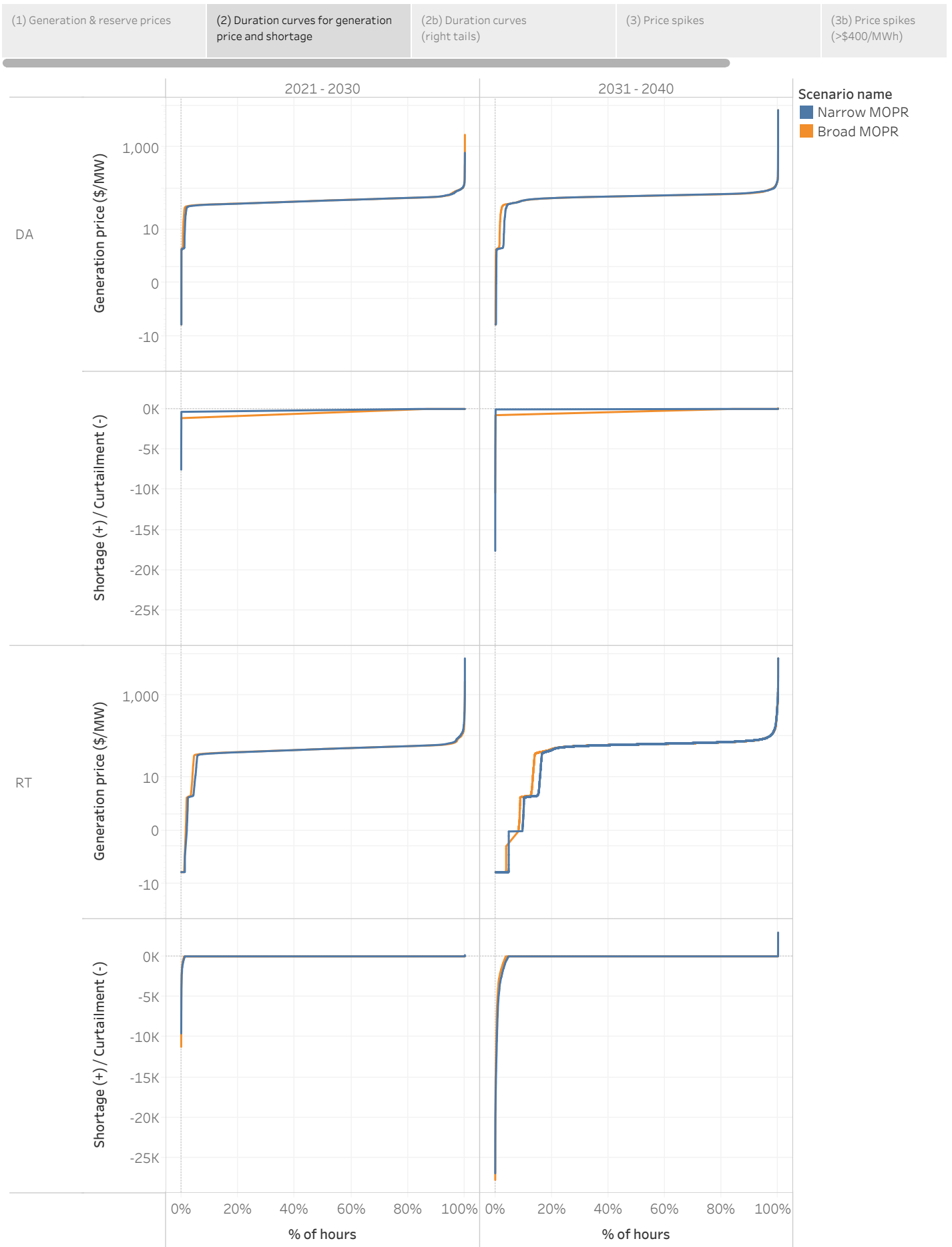


Figure 7: Right tail duration curves for generation price and shortage by decade

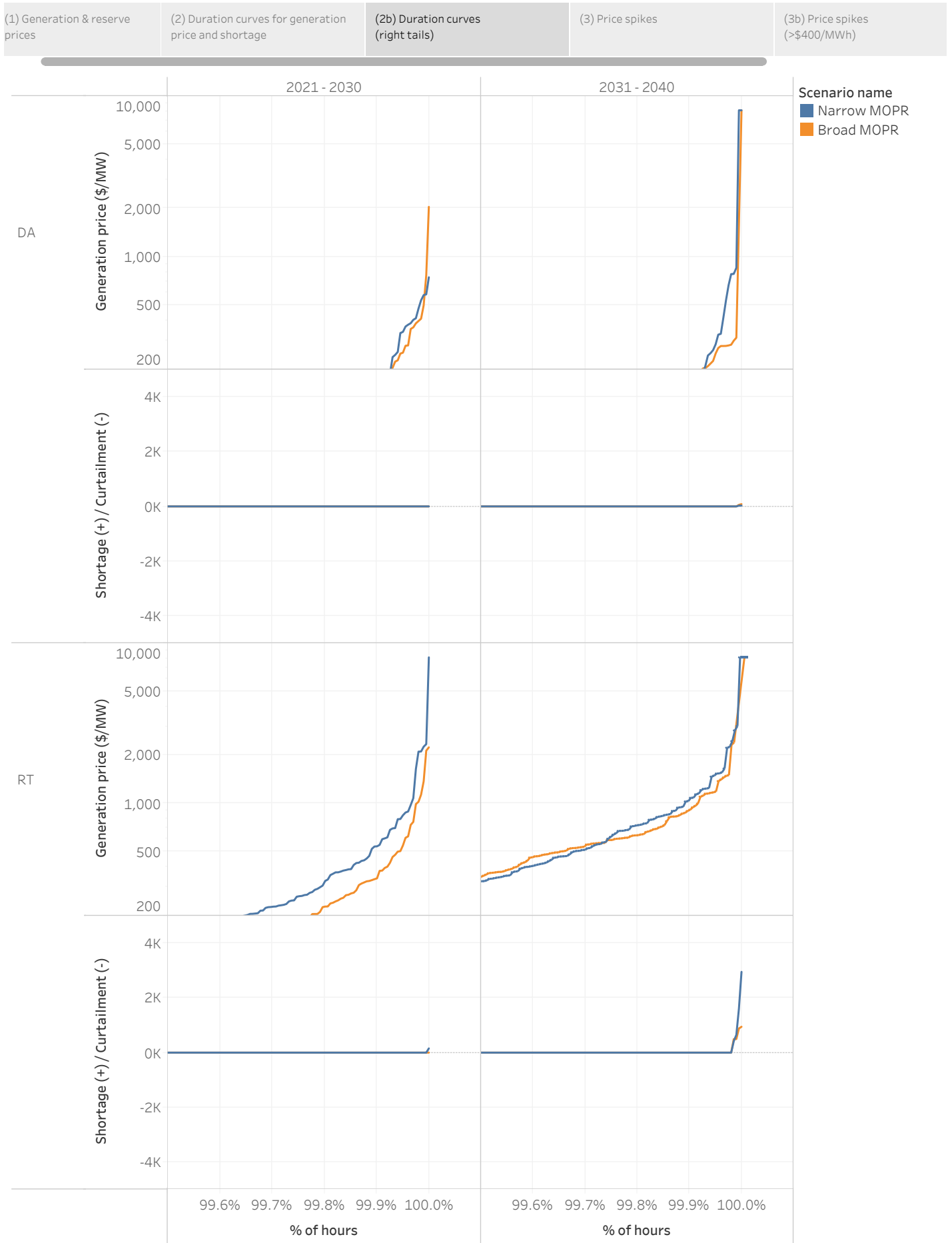


Figure 8: Price spikes in day-ahead and real-time markets by year, 2019-2040

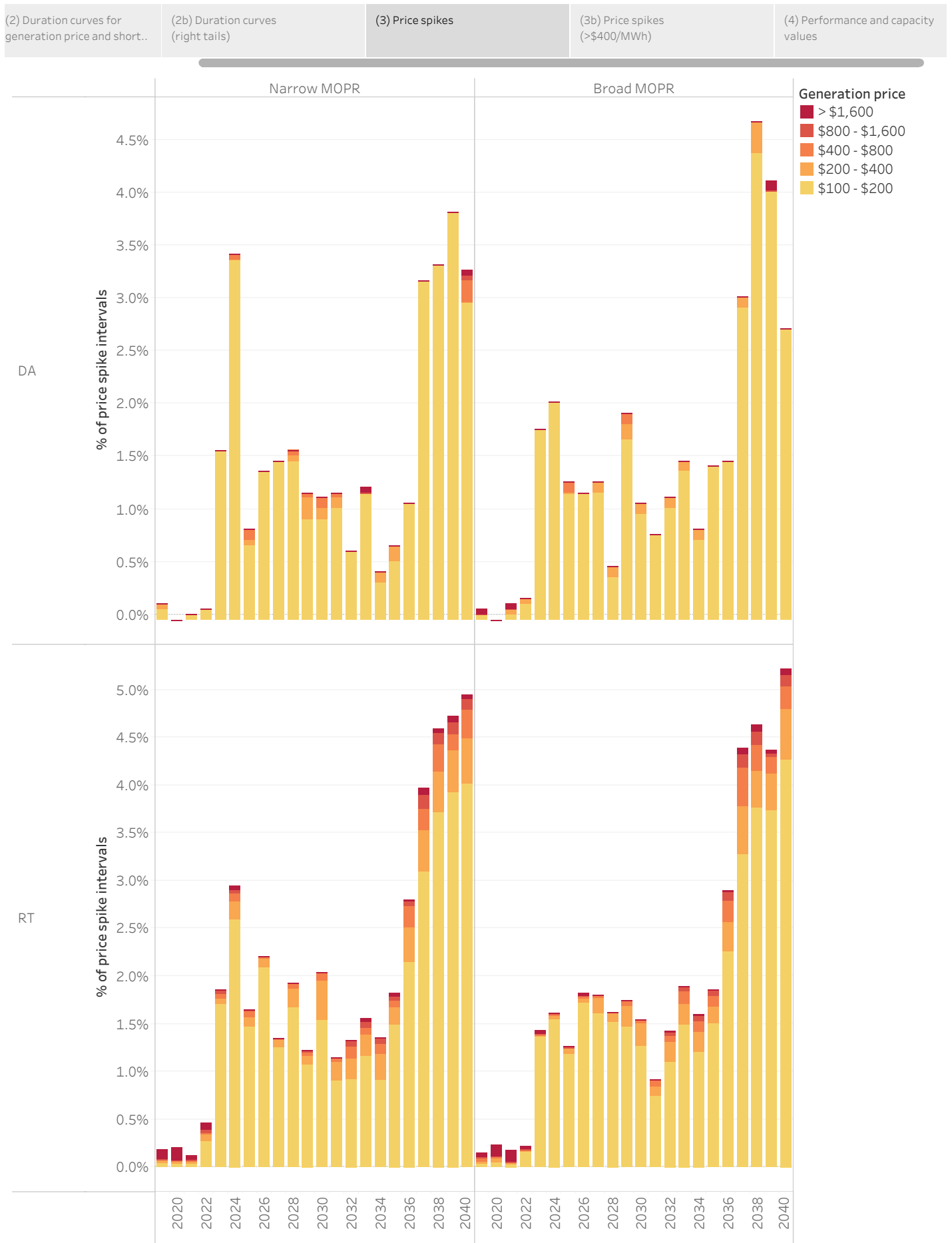


Figure 9: High price spikes in day-ahead and real-time markets by year, 2019-2040

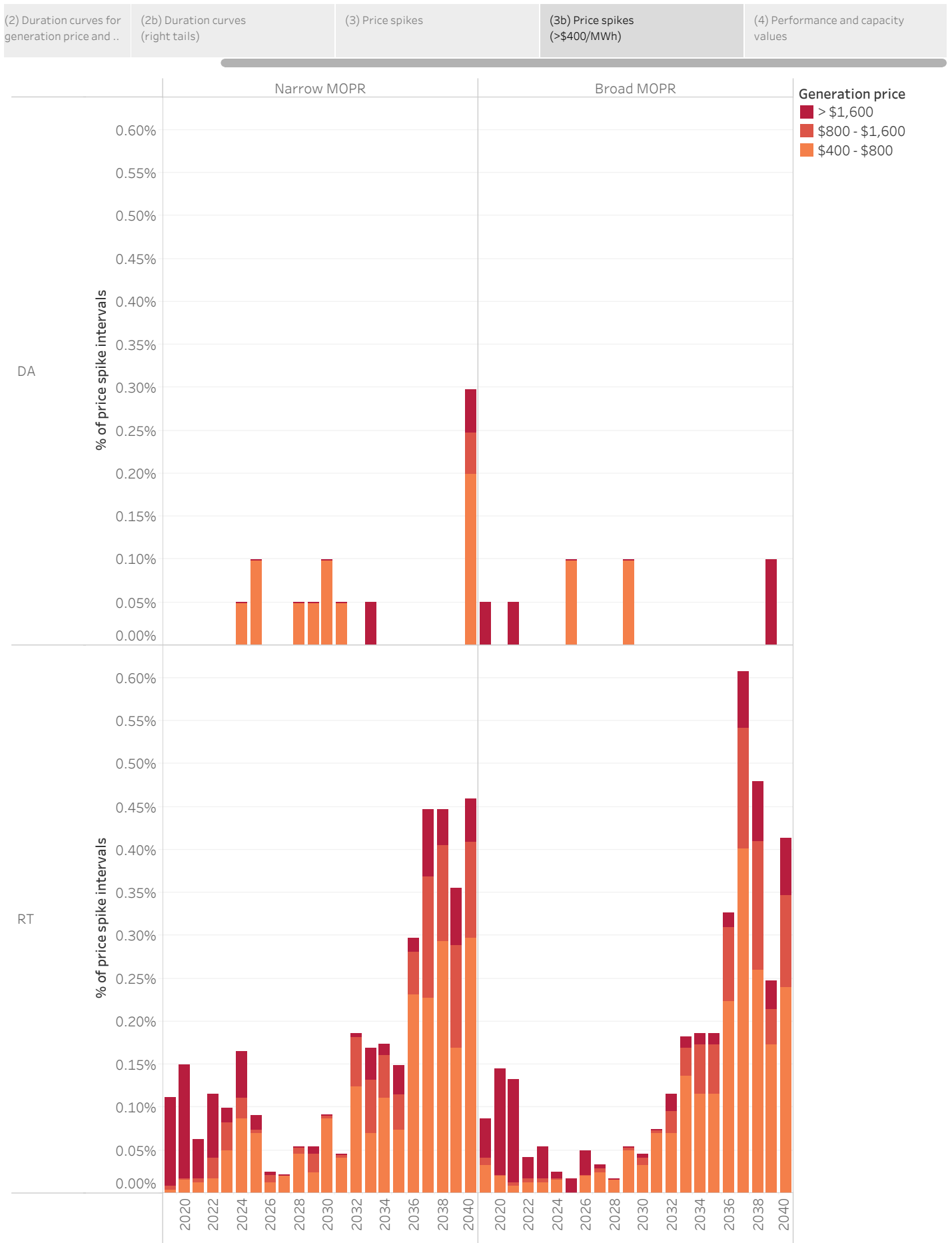




Figure 10: Electricity price components by year, 2019-2040

Electricity price components

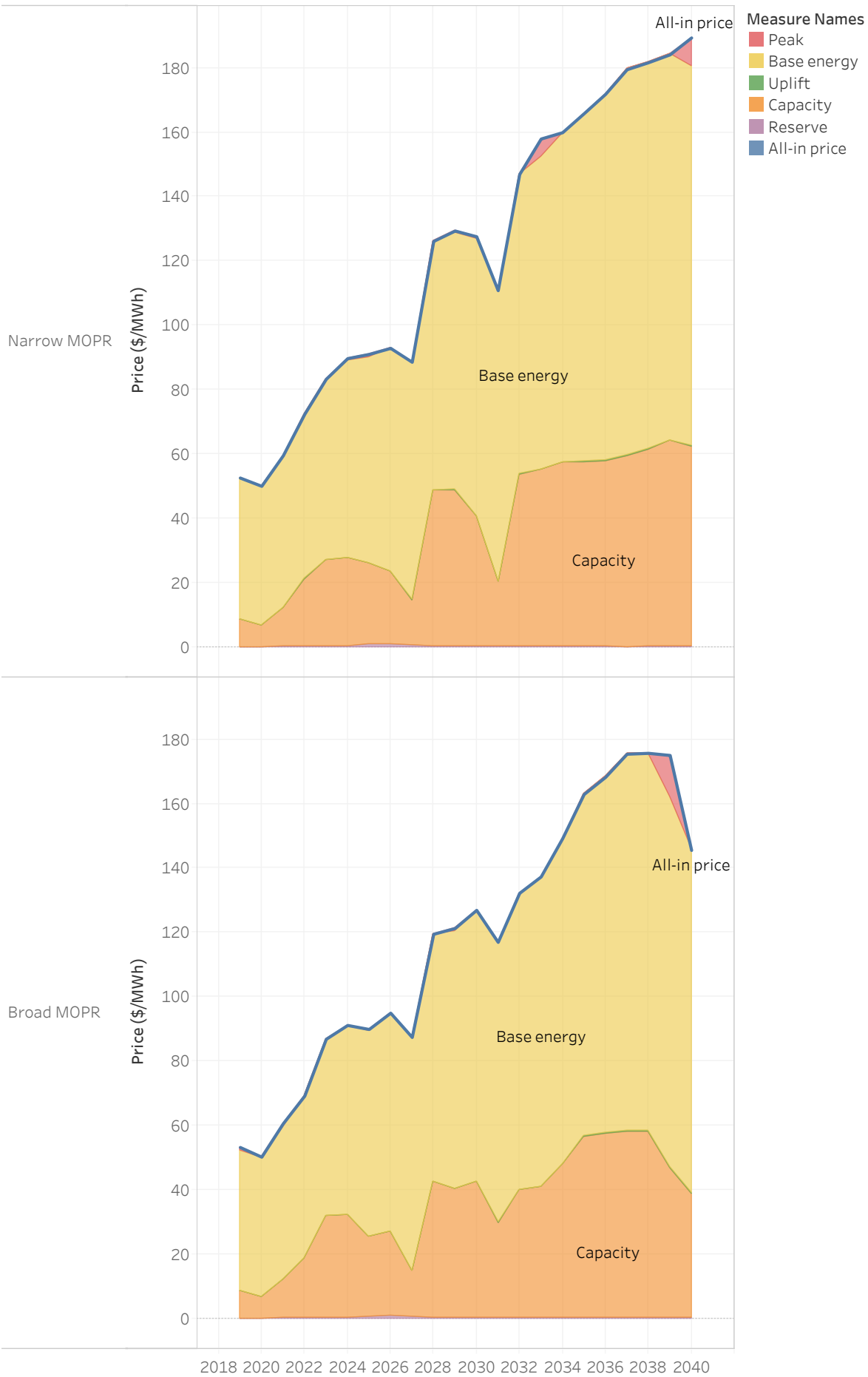


Figure 11: Electricity cost components by year, 2019-2040

Electricity cost components

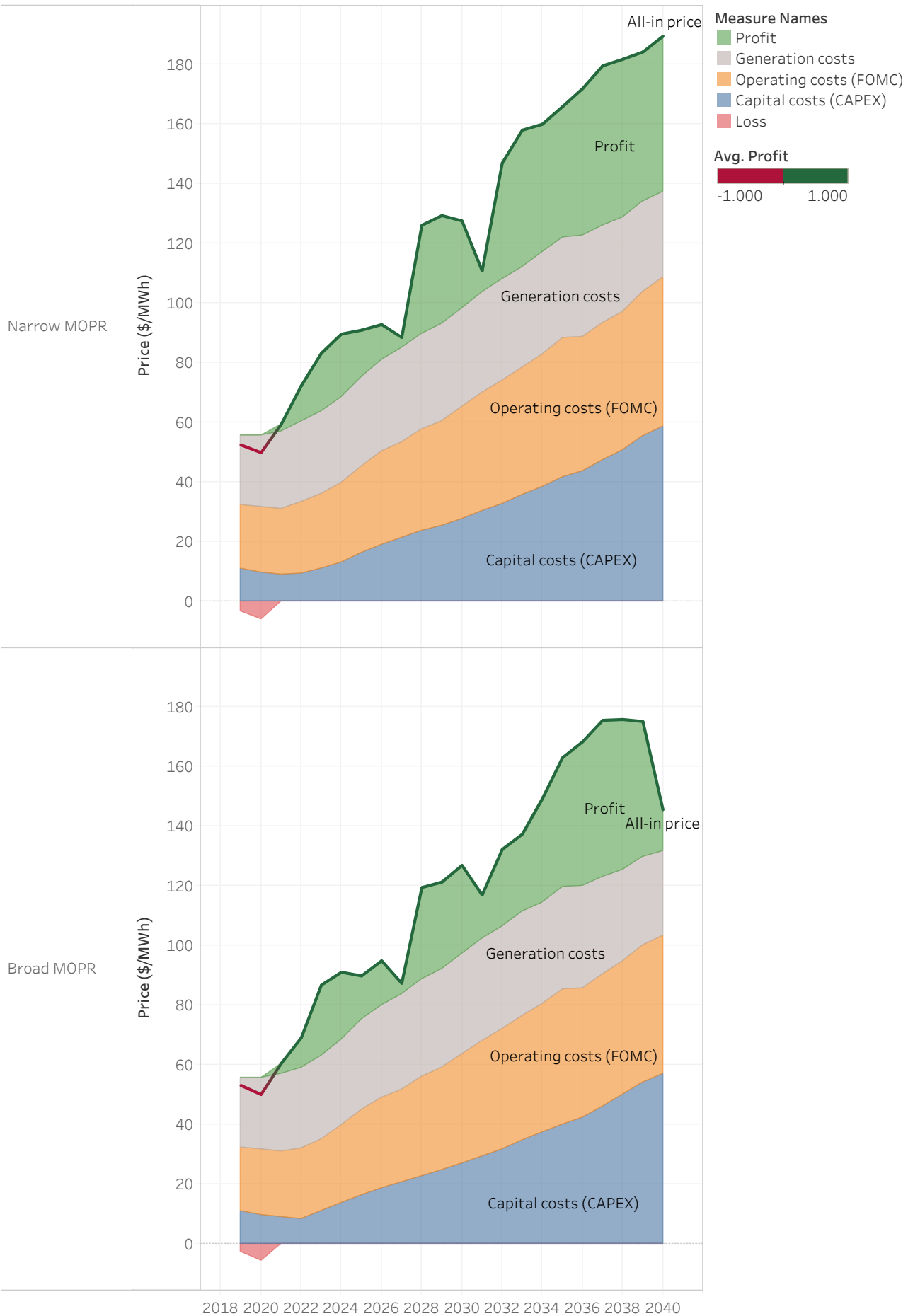


Figure 12: Performance and capacity values by decade

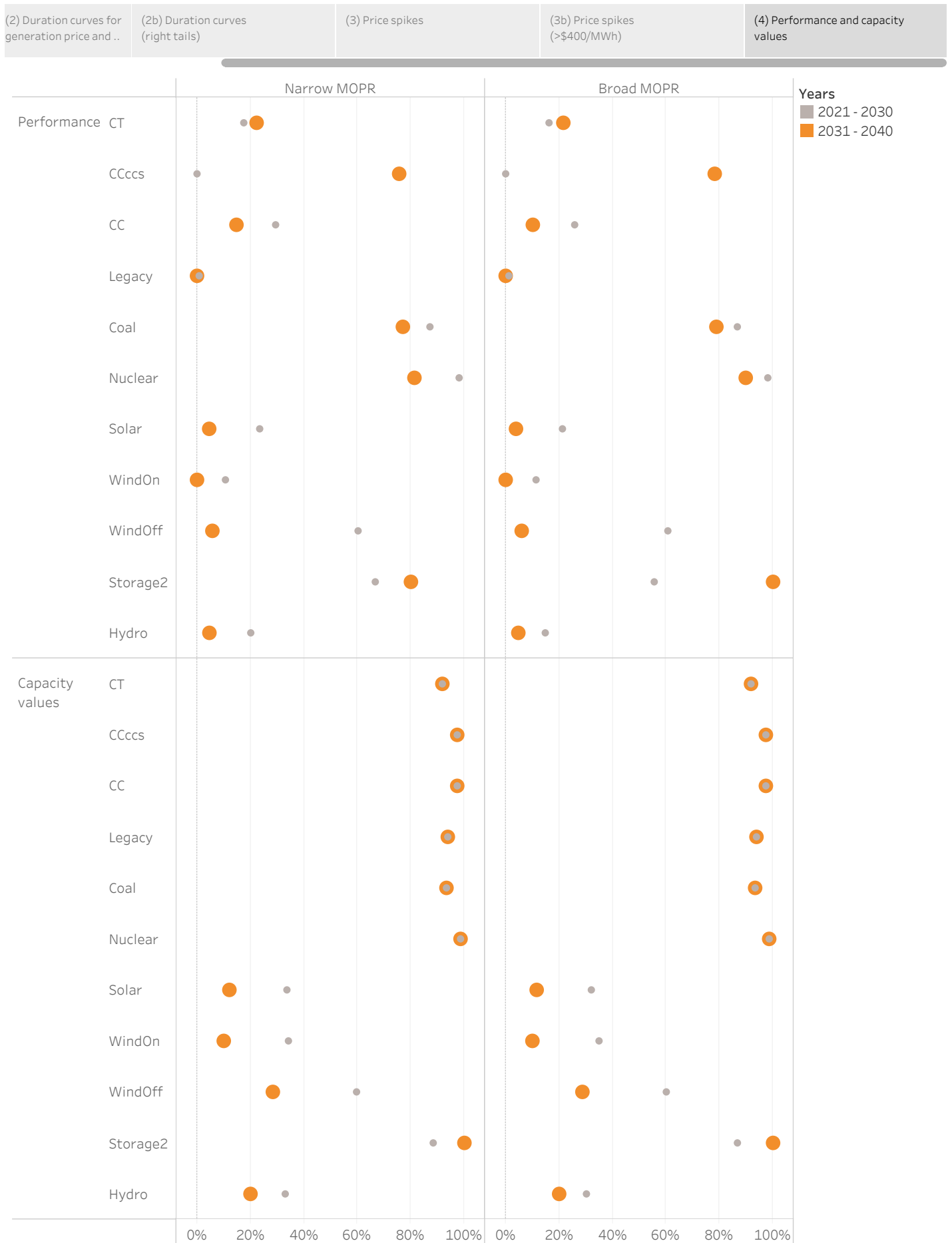


Figure 13: Average annual net entries by decade

Entries & exits by decade

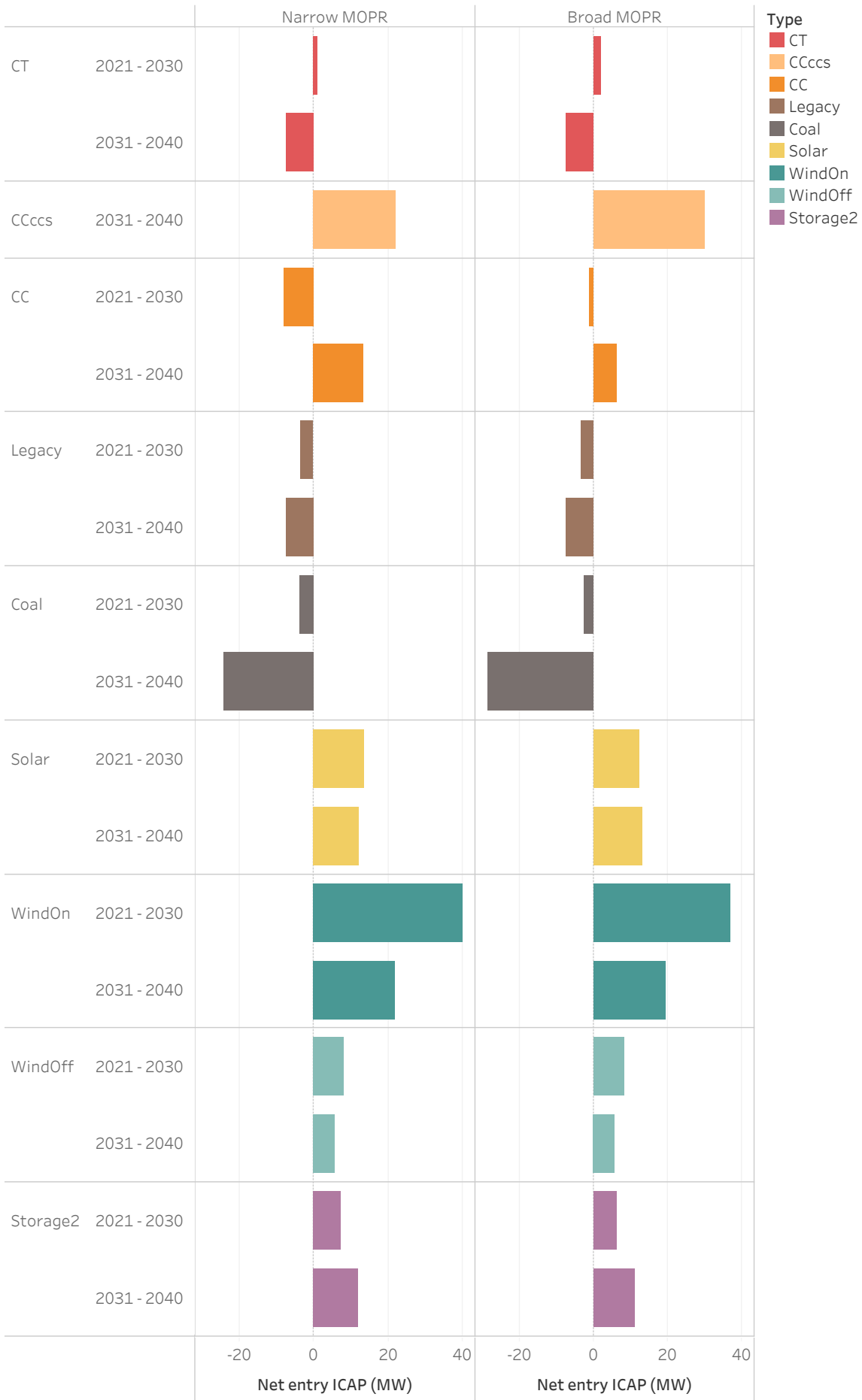


Figure 14: Net present value of incumbent resources by year, 2019-2040

(1) Effects on net entries	(2) Effects on energy mix	(3) Incumbent NPV	(4) New entrant NPV
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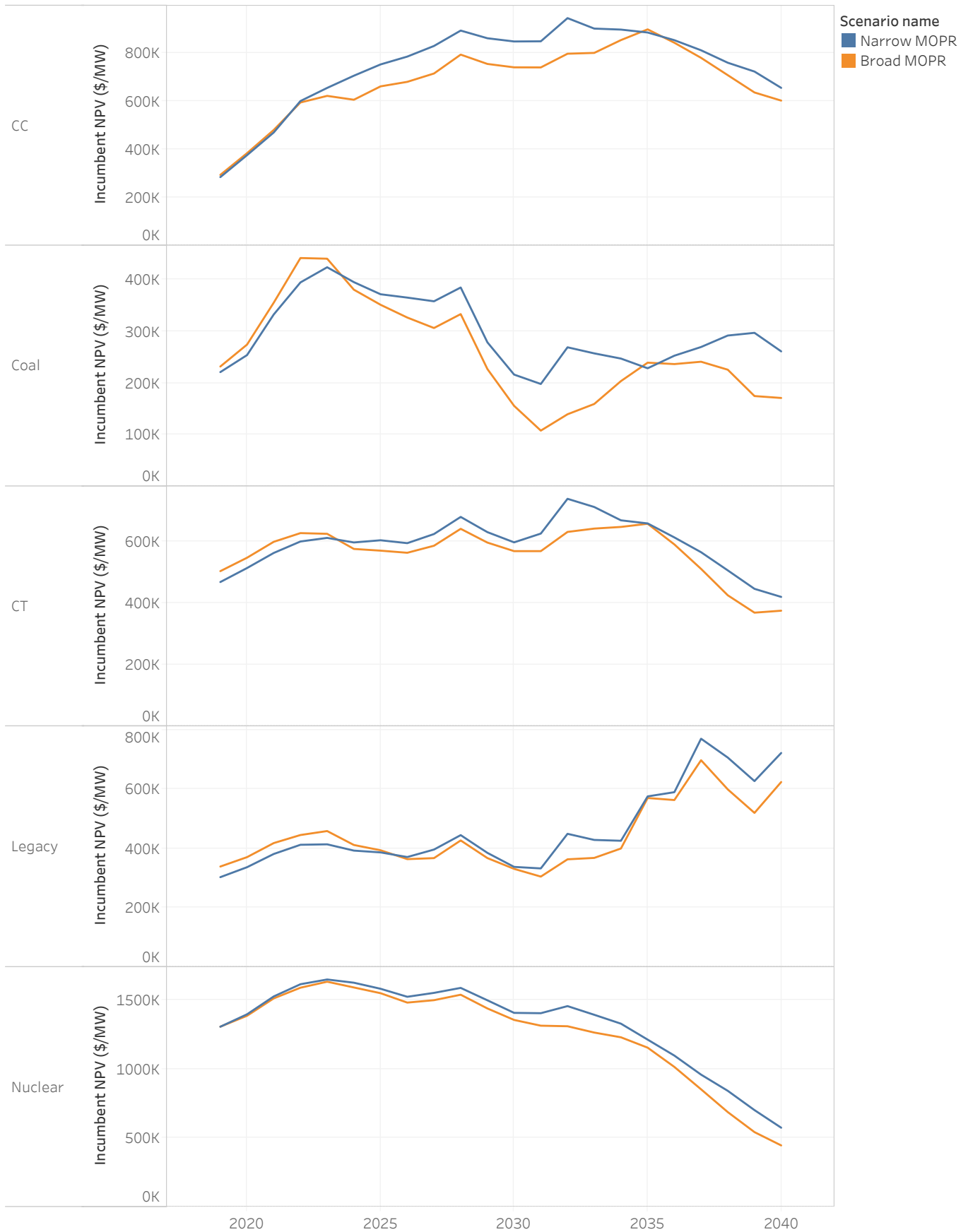


Figure 15: New entrant net present value by year, 2019-2040

(1) Effects on net entries	(2) Effects on energy mix	(3) Incumbent NPV	(4) New entrant NPV
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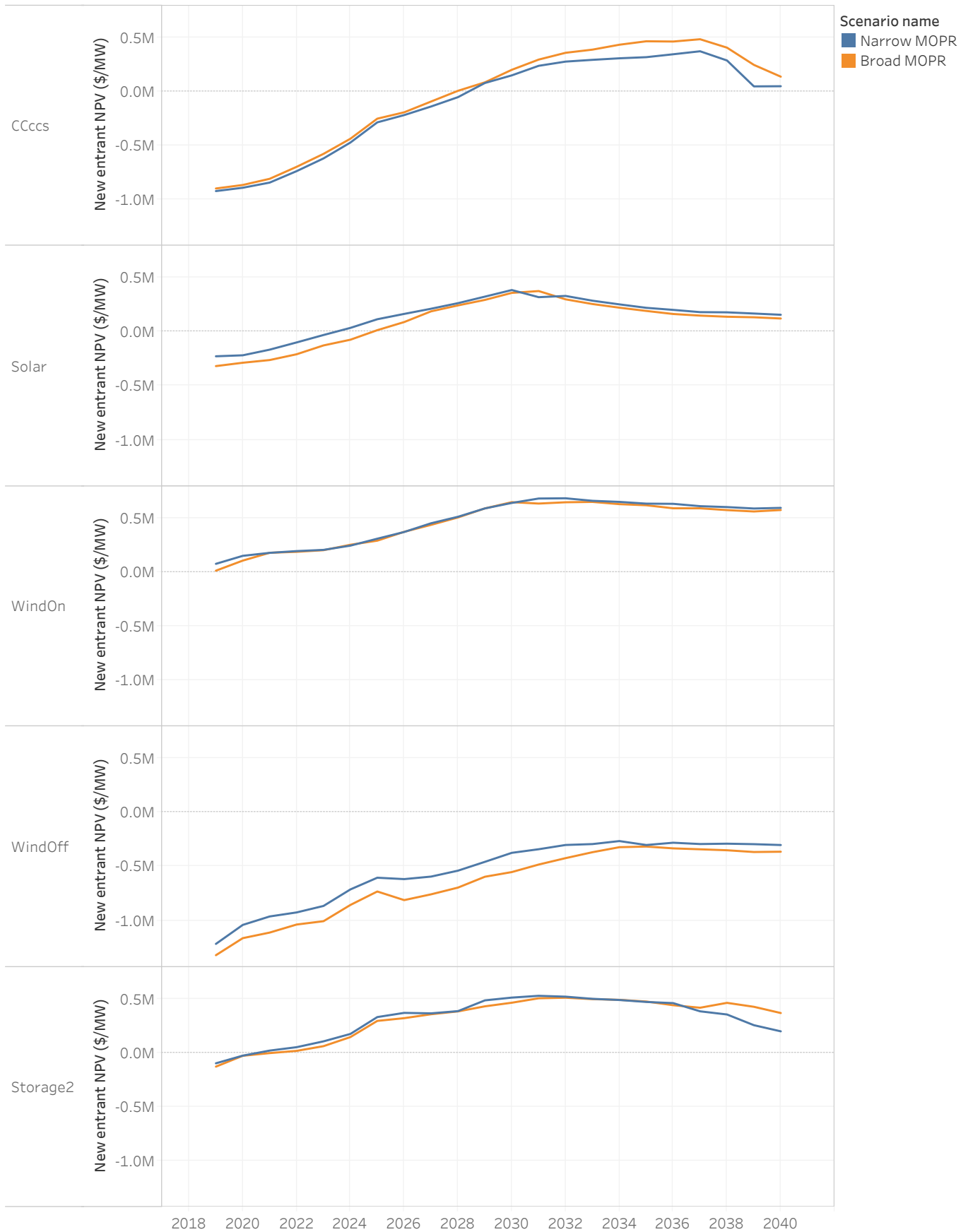
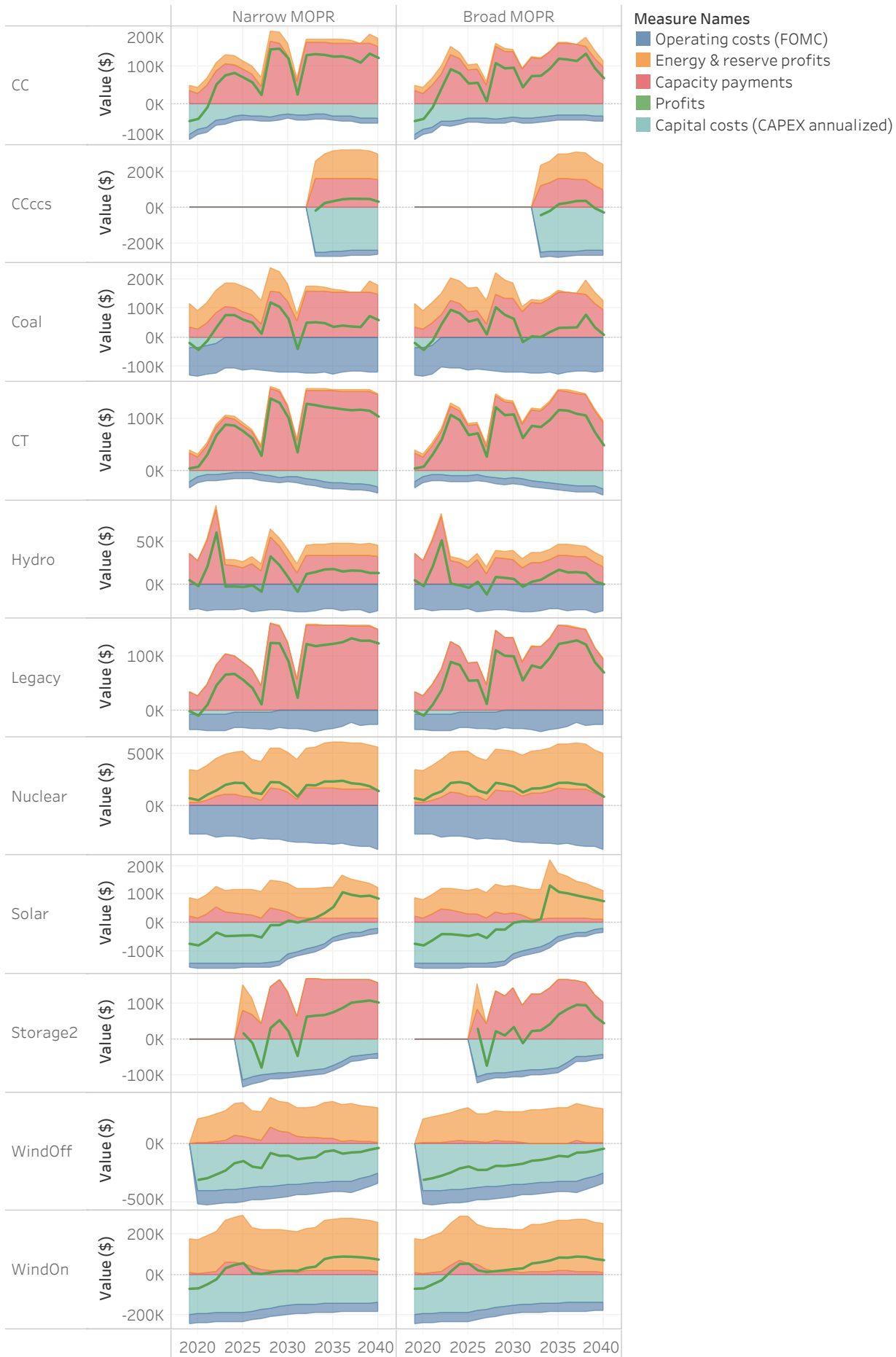


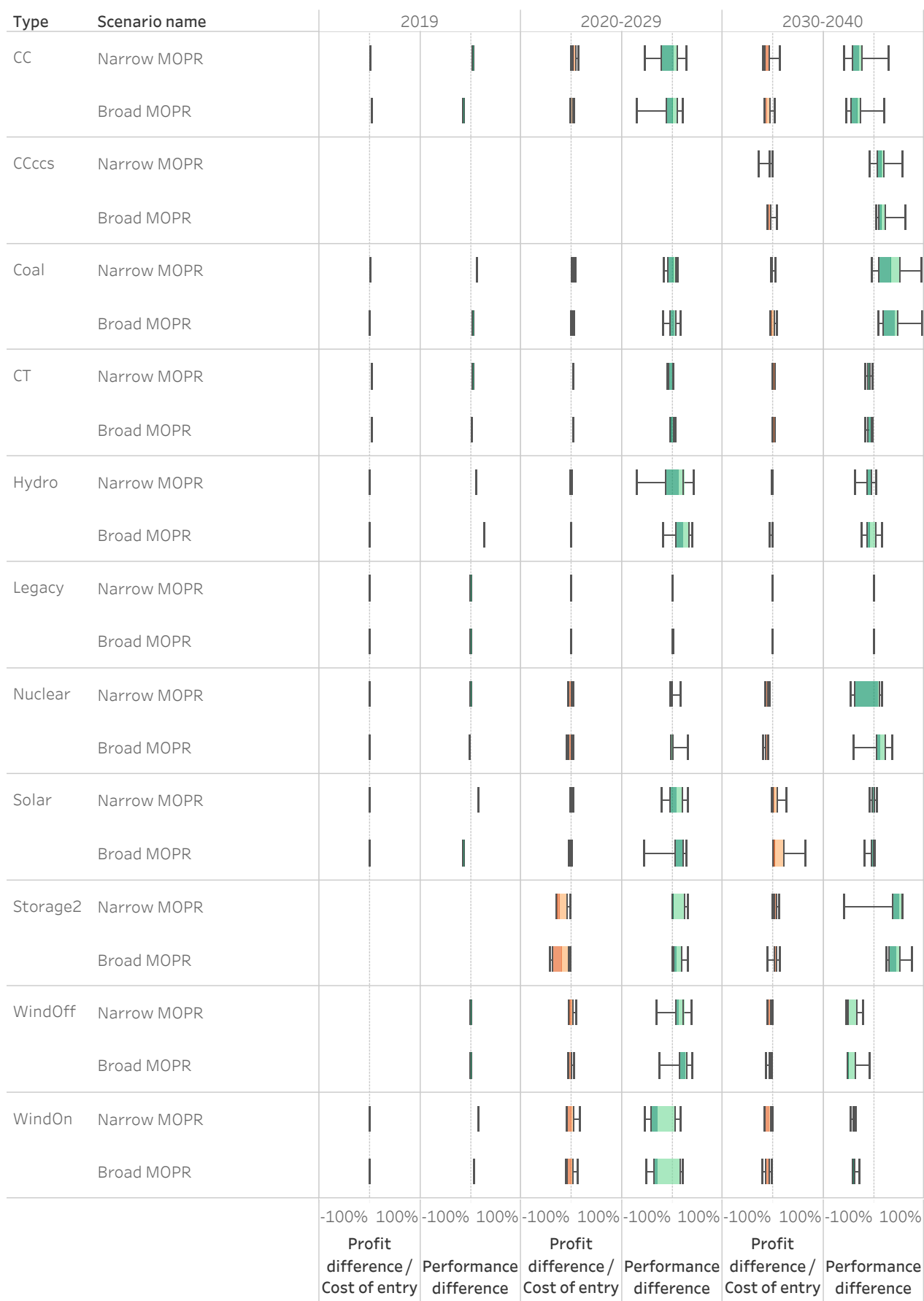
Figure 16: Profit breakdown by year, 2019-2040

Profit breakdown



**Figure 17: Deviations of proxy model and energy market model along the equilibrium path**

Profits and performance predicted by the energy proxy minus actual profits and performance generated by the energy market model along the equilibrium path (profits are divided by the annualized cost of entry in 2019)







# Attachment D

Affidavit of Adam J. Keech  
on behalf of PJM Interconnection, L.L.C.



4. I have worked at PJM since January 2003. I hold a Bachelor's of Science degree in Electrical Engineering from Rutgers University in New Brunswick, NJ and a Master's of Science degree in Applied Statistics from West Chester University in West Chester, PA.
5. The purpose of my affidavit is to discuss why changes to the MOPR are necessary at this time. I also explain why PJM's proposal reasonably responds to changed circumstances relative to past PJM MOPR proposals.

### **Background**

6. In December 2019, the Federal Energy Regulatory Commission ("Commission" or "FERC") ordered an expanded version of the MOPR ("2019 MOPR"), as the culmination of a multi-year proceeding that began in 2016 with a complaint filed against the version of MOPR in place at that time.<sup>1</sup> The 2019 MOPR seeks to apply the MOPR to out-of-market support from states, political subdivisions of states, and self-supply business models. The focus of this MOPR is not buyer-side market power but price-suppression.
7. The 2019 MOPR creates two fundamental problems:
  - In its quest to cleanse market-clearing prices from the impacts of subsidies, it distorts prices in such a way that they do not represent the underlying fundamentals of capacity supply and demand in PJM.
  - It makes it risky for certain entities to continue to participate in the capacity market and simultaneously carry out the functions they have the legal right to perform. This risk stems from the potential for double payment. A state, Load Serving Entity ("LSE"), or other entity may contract for a resource that then does not clear in the capacity market if MOPR raises the resource's offer price above the price-clearing level. This results in consumers paying for capacity twice: first, the cost of the contracted capacity; second, the allocated cost of additional capacity from the PJM market because the contracted resource did not clear. This makes it more difficult for self-supply entities to carry out their basic function of contracting for supply on behalf of their member companies based on their long-range plans. This also makes it more difficult for states to meet their policy goals to promote or support certain resource types.

### **The 2019 MOPR incents capacity market withdrawal that is ultimately more harmful to the capacity market than the conduct that the 2019 MOPR attempts to address**

8. The 2019 MOPR is not sustainable because it forces states and self-supply entities to make a binary decision on whether to participate in the capacity market fully or meet their policy goals when the capacity market rules do not align with their policy objectives. Evidence suggests that states and self-supply entities are more likely to exit the capacity market to meet their policy and business objectives than remain in the capacity market and curtail

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<sup>1</sup> See *PJM Interconnection, L.L.C.*, 169 FERC ¶ 61,239 (2019) ("December 2019 Order").

those objectives. For example, when faced with that decision, Dominion Energy chose to exit the capacity market, by electing the Fixed Resource Requirement (“FRR”) for the most-recent Base Residual Auction for the 2022/2023 Delivery Year.<sup>2</sup> In addition, New Jersey, Illinois, and Maryland, either through administrative proceedings or legislative initiatives, have all considered in their respective states potentially exiting the capacity market,<sup>3</sup> and it is expected those discussions will resume without meaningful, immediate MOPR reform. When a state, LSE, or self-supply entity removes its entire footprint from the capacity auction, the load within that footprint must meet its capacity obligation through other means. Typically this occurs either through self-supply or using bilaterally contracted resources. In either case, it is likely to result in resources serving the capacity obligation of that load that would either in total, or in-part, not clear in the market.

9. For example, assume utility A would like to serve 20% of their obligation with renewable resources and the remaining 80% with the most economic resources possible. If utility A does not believe that the capacity market will meet their objective of 20% renewables due to the MOPR, the alternative they have is to elect FRR. If they elect FRR, they generally must do so for 100% of their load based on the current rules. By taking this step, they may be able to meet their renewable objective but because they must also meet the remaining 80% of their obligation through non-market means such as self-supply or bilateral contracts, it is almost a certainty that not all of the remaining 80% of their load will be served by the most economic resources on the system. When viewed in the market context, this effectively results in resources that are uneconomic, receiving a capacity commitment which will have a further downward pressure on the price above and beyond that which may have been caused by the desire to meet 20% of the obligation with renewables.
10. Confirming this expected impact, the Independent Market Monitor, (“IMM”) in 2019 released a report<sup>4</sup> containing analysis that quantified the impact of a Commonwealth Edison Co. (“COMED”) FRR election. In 2021, the IMM released a similar report<sup>5</sup> with various scenarios to quantify the impact of an FRR election for various LSEs in the state of Virginia. In both cases, the shift of large portions of PJM load from the market to FRR

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<sup>2</sup> Rich Heidorn Jr., *Dominion Opts out of PJM Capacity Auction*, Rich Heidorn Jr., RTO Insider (May 6, 2021), <https://www.rtoinsider.com/articles/20192-dominion-opts-out-of-pjm-capacity-auction>; *see also* Sarah Vogelsong, *Dominion’s exit from regional capacity market raises some eyebrows – and questions*, Virginia Mercury (May 25, 2021), <https://www.virginiamercury.com/2021/05/25/dominions-exit-from-regional-capacity-market-raises-some-eyebrows-and-questions/>.

<sup>3</sup> *See In the Matter of BPU Investigation of Resource Adequacy Alternatives*, Order Initiating Proceeding, Docket No. Docket No. EO20030203 (Mar. 27, 2020) (the New Jersey Board of Public Utilities is staying its proceeding precisely because it anticipated this filing to replace the Expanded MOPR); Clean Energy Jobs Act, Ill. SB2248, 102nd Gen. Assembly, State of Ill. (Feb. 26, 2021) (introduced by Sen. Collins); Kathleen Spees, et al., *Alternative Resource Adequacy Structures for Maryland*, Maryland Energy Administration (March 2021), <https://energy.maryland.gov/Reports/Alternative%20Resource%20Adequacy%20Structures%20for%20Maryland%20Final%20Brattle%20Study%20March%202021.pdf>.

<sup>4</sup> *Potential Impacts of the Creation of a COMED FRR*, The Independent Market Monitor for PJM (Dec. 18, 2019), [https://www.monitoringanalytics.com/reports/Reports/2019/IMM\\_Potential\\_Impacts\\_of\\_the\\_Creation\\_of\\_a\\_CoMED\\_FRR\\_20191218.pdf](https://www.monitoringanalytics.com/reports/Reports/2019/IMM_Potential_Impacts_of_the_Creation_of_a_CoMED_FRR_20191218.pdf).

<sup>5</sup> *Potential Impacts of the Creation of Virginia FRRs*, The Independent Market Monitor for PJM (May 18, 2021), [https://www.monitoringanalytics.com/Reports/reports/2021/IMM\\_VA\\_FRR\\_Report\\_20210518.pdf](https://www.monitoringanalytics.com/Reports/reports/2021/IMM_VA_FRR_Report_20210518.pdf).

has substantial impacts on the market. These changes have a far greater impact on the market than simply re-focusing the MOPR back on buyer-side market power. In short, the 2019 MOPR exacerbates the very price suppression issue it seeks to mitigate because it can motivate entities to take their entire portfolio out of the market.

**The 2019 MOPR ignores that state support for renewable resources has become a well-established determinant of supply in the PJM Region, and thus ignores the current supply-demand fundamentals.**

11. The 2019 MOPR also can yield unreasonable results when the underlying behavior resulting in the application of the MOPR is not changed by its application. For example, if a state subsidizes an existing coal unit with a high Net ACR understanding that the resource will not clear the capacity auction because it will trigger the MOPR, applying the MOPR results in a price signal for more capacity that is not needed given the coal unit will still be in operation. In that scenario, consumers in the state pay twice, i.e., for both the coal unit and the resource committed through the auction because the coal plant did not clear. Customers that do not pay for the coal unit may also still see a cost increase, given the higher marginal cost of the resource that cleared in lieu of the coal unit. Conversely, leaving the coal unit in the market and allowing it to clear would send a lower price signal (relative to not clearing the resource by operation of the 2019 MOPR), but that result would be consistent with supply and demand fundamentals. Likewise, the price would be consistent with the marginal cost of capacity. Given the level and extent of state support for certain resources in the PJM Region, and the likelihood that support will persist, if not grow,<sup>6</sup> it is highly unlikely that the 2019 MOPR will result in chilling state policy actions to support favored resources. As stated previously, it is more likely that it incents entities to exit the capacity market. Those policies are now a well-established component of the supply of resources in the PJM Region, and the MOPR therefore must be reformed to restore price signals that are more consistent with actual supply and demand fundamentals.
12. Ultimately, if the capacity prices do not reflect the actions being taken by states and by self-supply entities because those resources are prevented by the MOPR from clearing the auction, then capacity prices will incentivize resources to be built that are not needed to maintain reliability. If the entities taking these actions remain in the capacity market, the market will produce prices that are too high. If investors responded to those elevated prices, the result will be systematic over-procurement. It is difficult to see how such prices are just and reasonable.

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<sup>6</sup> See, e.g., Virginia Clean Economy Act, HB 1526, 2020 Sess. (Va. 2020) (adopting a renewable portfolio standard that requires Phase 1 utilities to generate 100% of their power from renewable resources by 2045); An Act to Amend Title 26 of the Delaware Code Relating to Renewable Energy Standards, S.B. 33, 151st Gen. Assembly (Del. 2021) (increasing and extending state renewable portfolio standard to 40% renewable resources, including 10% solar photovoltaic resources, by 2035); Clean Energy DC Omnibus Amendment Act of 2018, D.C. Act 22-583 D.C. 2019) (increasing and extending state renewable portfolio standard to 100% tier 1 renewable resources, including 10% solar photovoltaic resources, by 2041); Maryland Clean Energy Jobs Act of 2019, S.B. 516, 2019 Sess. (Md. 2019) (increasing and extending state renewable portfolio standard to 50% tier 1 renewable resources, including 14.5% solar photovoltaic resources, by 2030).

**The 2019 MOPR fails to account for the changed circumstances associated with PJM’s expected imminent implementation of rules that will significantly affect the capacity contribution from renewable resources.**

13. The 2019 MOPR also fails to account for the likely imminent implementation of Effective Load Carrying Capability (“ELCC”). ELCC will take the necessary first step towards right-size the capacity accreditation for wind, solar and storage, and in doing so will also mitigate price impacts of what looks to be continued growth of these asset classes. When PJM proposed repricing in 2018, it was under the assumption that the capacity quantity and price impact of renewables would become more and more significant going forward. For intermittent technologies, ELCC has the opposite effect where the reliability contribution of such resources declines as the penetration level increases. The 2019 MOPR rests on the same assumption, which ELCC will change.

**The Legacy MOPR also should be eliminated.**

14. The “Legacy MOPR” is the MOPR that has been in place in PJM since prior to the December 2019 Order expanding the MOPR. In general, this MOPR only applies a non-zero MOPR Floor Price to new natural gas resources by default. The specific circumstances around the resource are not consequential to the application of the MOPR. If it is a new natural gas resource, it is subject to MOPR. The intent of this MOPR was to focus on buyer-side market power although its linkage to that is only through an assumption that a new natural gas resource would be the exclusive vehicle by which and entity would seek to exercise buyer-side market power.
15. The Legacy MOPR requires modification because as the FERC found in its 2019 Order, focusing on only new natural gas resources is arbitrarily narrow when it comes to a screen and rules to mitigate buyer-side market power.<sup>7</sup> PJM believes FERC was correct in this finding. Buyer side market power, while difficult to exert in general, could be exerted with an existing resource of any technology type in the same manner, perhaps even more cost-effectively, than it can be by building a new natural gas-fired combined cycle or combustion turbine. The Legacy MOPR also is overly broad in that it mitigates all new natural gas resources offers, even those from market sellers with no incentive to suppress prices and who would otherwise be expected to offer in a way that reflects economic costs. This includes purely merchant sellers that are not receiving out-of-market payments and that are not engaged in inappropriate bilateral contracts.

**MOPR remains a reasonable mitigation measure for the much more targeted application PJM is proposing here**

16. PJM’s proposal to apply the MOPR as a mitigation measure when the market rules are not being followed (i.e., pre-empted state policies and exercises of buyer-side market power) allows the market to clear without the impact of the rules infraction. PJM’s proposal retains MOPR as a mitigation measure when a seller attempts to exercise buyer-side market power, or when a state intrudes on FERC’s wholesale price setting authority by conditioning

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<sup>7</sup> See December 2019 Order at P 37.

financial support for a resource on that resource clearing in the wholesale capacity auction. That application is reasonable in these circumstances. Both such types of actions are plainly impermissible should not be permitted to have a detrimental effect the market. An offer floor is a reasonable means to protect the wholesale market in these more narrowly defined circumstances.

**PJM's New Proposal Represents a Reasonable Evolution from PJM's Views on Past MOPR Proposals.**

17. In 2018, PJM filed Capacity Repricing as part of the “jump ball” filing, which targeted MOPR reform in response FERC’s granting of the 2016 complaint.<sup>8</sup> That proposal was formulated to do two primary things:
  - Accommodate states by allowing resources that were considered subsidized to receive a capacity commitment.
  - Calculate a market clearing price that removed the impact of the aforementioned subsidies by performing repricing when there was a significant number of subsidized MWs clearing.
18. From PJM’s perspective, we believed this proposal struck a balance between accommodating states and being responsive to the price suppression issues raised by the complainants in 2016 and granted by the Commission in 2018. At that time, there was a view that the growing level of Renewable Portfolio Standards would create an environment of continued price suppression into the future that needed to be addressed. The specific accommodations of this proposal included:
  - 20MW Unforced Capacity (“UCAP”) minimum threshold for application of the MOPR to a resource;
  - 1% total annual revenues de minimis threshold;
  - Exemption for resources whose primary reason for operation is not electricity generation; and
  - 5,000 MW or 3.5% quantity threshold in the Regional Transmission Organization (“RTO”) and Locational Delivery Areas (“LDAs”), respectively, for application of MOPR and use of repricing.
19. While PJM supported strengthening the MOPR in that proceeding, all of those accommodations were intended to result in the application of the MOPR when the individual resource size was large and the subsidy size was material. The use of repricing was reserved for when the price impact was expected to be material.

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<sup>8</sup> *PJM Interconnection, L.L.C.*, Capacity Repricing or in the Alternative MOPR-Ex Proposal: Tariff Revisions to Address Impacts of State Public Policies on the PJM Capacity Market, Docket No. ER18-1314-000 (Apr. 9, 2018).



20. This approach was rejected by the Commission (along with its sister proposal MOPR-Ex) in June 2018.<sup>9</sup> In FERC's order rejecting repricing, they found that the dislocation between the cleared MWs and clearing prices resulting from the repricing proposal resulted in distorted prices. On this issue, PJM now believes the FERC was correct and that repricing-style approaches are flawed. The prices resulting from such proposals deviate from the supply and demand fundamentals of the underlying market. Such repricing is a problematic market design because even though the prices would represent what they would have been without subsidies, they don't provide the right signals for investment and retirement which is a primary objective of the capacity market. They are systematically too high and would indicate a need for more capacity that is not real.
21. Given all of these factors, and the overwhelming stakeholder support for reform, I believe that now is the time to make meaningful reforms to the MOPR by accepting the proposal contained in this filing.
22. This concludes my affidavit.

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<sup>9</sup> *PJM Interconnection, L.L.C.*, 163 FERC ¶ 61,236 (2018).



**UNITED STATES OF AMERICA  
BEFORE THE  
FEDERAL ENERGY REGULATORY COMMISSION**

**PJM Interconnection, L.L.C.**

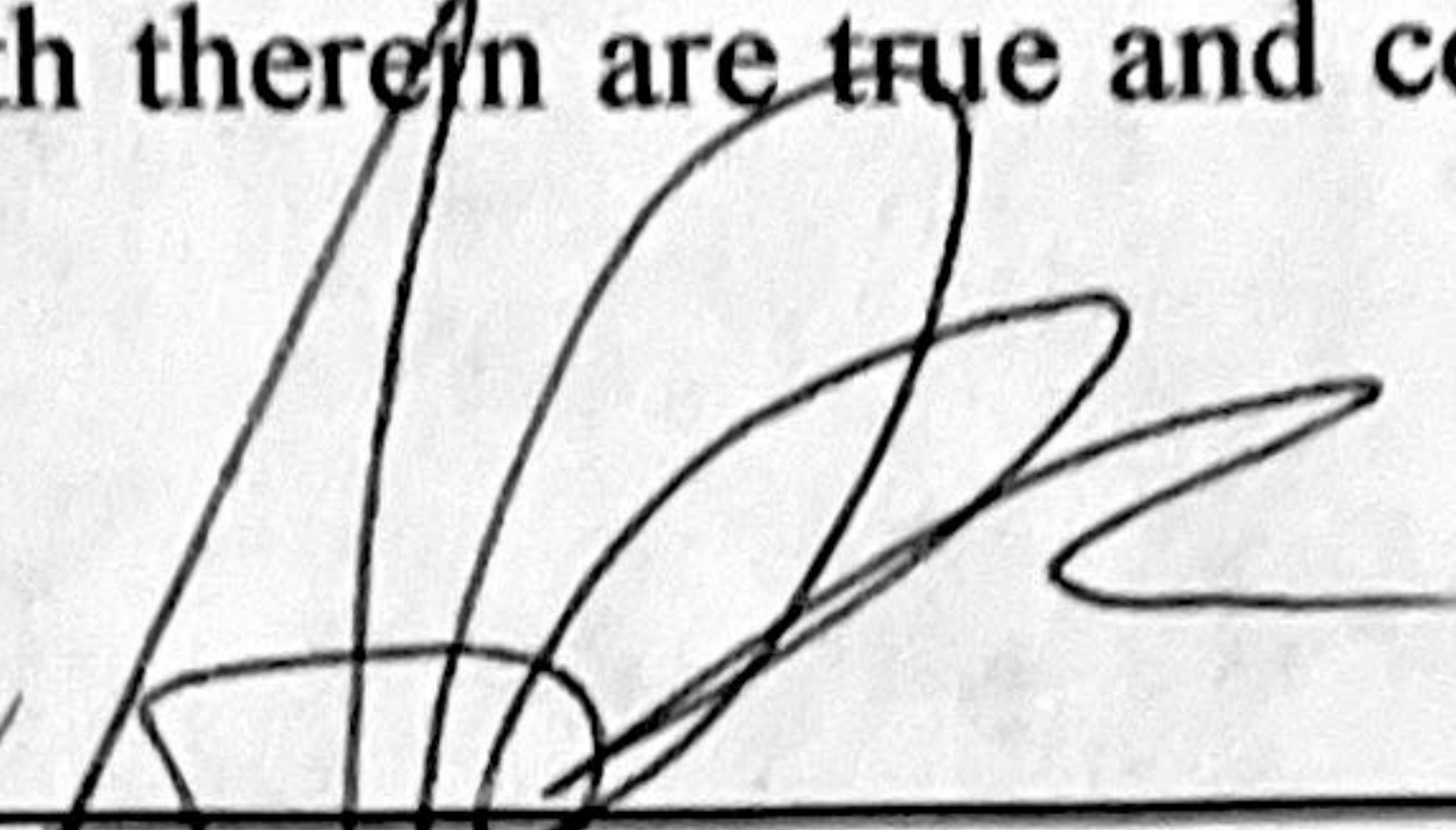
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**Docket No. ER21-\_\_\_\_-000**

**VERIFICATION**

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

/s/

  
\_\_\_\_\_  
Adam J. Keech

Vice President of Market Design and Economics  
PJM Interconnection, L.L.C.



# Attachment E

Affidavit of Dr. Walter F. Graf  
on behalf of PJM Interconnection, L.L.C.



4. I received Bachelor's of Science degrees in Economics and Civil and Environmental Engineering from the University of Michigan in Ann Arbor, MI. I received a Master's of Science degree and a Doctor of Philosophy degree in Agricultural and Resource Economics from the University of California in Berkeley, CA.
5. My affidavit supports PJM's filing with regard to applying the MOPR to protect against exercises of buyer-side market power. To that end, I explain PJM's approach to defining Buyer-Side Market Power and how the current expanded MOPR is too broad to accurately protect against exercises of buyer-side market power. Then, I describe PJM's new more focused MOPR's protection against buyer-side market power and how PJM will test for potential exercises of buyer-side market power. In addition, I explain why PJM's longstanding approach for using the net cost of new entry ("Net CONE") to determine the MOPR Floor Offer Price of resources that have never cleared a Reliability Pricing Model ("RPM") Auction is reasonable and appropriate.

### **Buyer-Side Market Power Definition**

6. PJM proposes to focus the scope of MOPR to more directly mitigate the Exercise of Buyer-Side Market Power. Buyer-Side Market Power and the Exercise of Buyer-Side Market Power are fundamentally economic concepts reflecting a set of incentives and behaviors that may be observed in any market. PJM's proposed definitions of these concepts in the context of its capacity market, known as RPM, allow for a focused application of MOPR to Capacity Market Sellers whose actions may distort market outcomes. PJM also proposes to apply the MOPR when a resource receives state support conditional on either clearing the capacity market or specific bid offer activity; this application of the MOPR is described more fully in Ms. Morelli's affidavit. My affidavit focuses on application of the MOPR for the purpose of mitigating buyer-side market power.
7. In this filing, PJM proposes to define Buyer-Side Market Power as "The ability of Capacity Market Sellers with a Load Interest to suppress RPM Auction clearing prices for the overall benefit of their (and/or affiliates) portfolio of generation and load."<sup>1</sup> The definition necessarily rests on two key elements. First, the Capacity Market Seller must have the *ability* to suppress prices, relative to competitive levels. The reason for this requirement is obvious—without the ability to suppress prices, a seller would not uneconomically lower their offer, as doing so would be unprofitable. Second, the market participant must have a load interest which causes them to have an *incentive* to suppress prices. Whether a seller has an incentive to suppress prices is measured on a net basis. The load interest must be sufficiently large that the expected benefit to the seller resulting from paying depressed capacity prices is larger than the cost of offering a resource below its economic costs and receiving market revenues which are insufficient to cover economic costs.
8. It is reasonable to require such economic incentive in defining Buyer-Side Market Power, as a resource offer that may appear too low to reflect costs is not, in and of itself, problematic for the integrity of market outcomes. For example, sellers could be accounting for non-PJM Market revenue streams (e.g., renewable energy credits) to cover resource

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<sup>1</sup> Proposed Tariff, Definitions – A-B (Buyer-Side Market Power).

costs not otherwise recovered through the capacity, energy, or ancillary services markets. Or, customers of a seller could be willing to absorb resource costs not otherwise recovered through the PJM Markets in order to receive energy and capacity from a favored resource type. More generally, Market Participants with no incentive to distort prices may disagree as to the profit-maximizing offer for a given resource, reflecting different understandings and forecasts of market fundamentals, future revenues, expected costs, and other factors.<sup>2</sup>

9. PJM proposes to define the Exercise of Buyer-Side Market Power in the context of the PJM capacity market as “Anti-competitive behavior of a market participant with a load interest, or directed by a load interest, to uneconomically lower capacity market offers in order to suppress market clearing prices for the overall benefit of the Capacity Market Seller’s portfolio or that of the directing load interest.” In addition to the ability and incentive elements described above, the Exercise of Buyer-Side Market Power requires *uneconomic behavior* to lower market offers below the competitive level to suppress prices. It is this behavior, when observed in the context of a market participant with both the ability and incentive to suppress market prices, that is prohibited and mitigated under the PJM proposal. Permitting such behavior would lead to inefficient market outcomes and reduce the benefit that buyers and sellers receive from a fair market.
10. Buyer-Side Market Power is not symmetrical to supplier-side market power in the PJM capacity market. Supplier-side market power is exercised by economic or physical withholding of the supply of capacity. Withholding an otherwise economic resource contracts the market supply curve—moving clearing outcomes up the demand curve, with higher prices and lower quantities served. However, buyers with the ability and incentive to suppress prices cannot symmetrically and directly withhold demand for capacity from the market, as demand is determined through an administrative demand curve, based on forecasted peak demand plus a reserve margin. Because buyers cannot use demand withholding to favorably affect market prices, participants with buyer-side market power instead must offer an uneconomic resource (i.e., a resource that generally would not clear the market) sufficiently below its economic cost that it clears, displaces more expensive (but economic) resources, and lowers the clearing price. Such can be accomplished through one of the following options.

### ***Constructing a new uneconomic resource***

11. Constructing a new resource entails a long-term commitment. Recouping the above-market costs of that resource would require that the resource sufficiently suppresses market prices over multiple years, such that the benefits exceed the costs. However, the long-run supply of capacity is relatively elastic, meaning that other Capacity Market Sellers would adjust their capacity supply offers over time in response to the suppressed prices. This predictable economic response limits the extent to which uneconomic resources can suppress market prices in the long-run. That expected response therefore undermines the rationale and efficacy of a strategy to exercise buyer-side market power through offering a new uneconomic resource. The market participant with buyer-side market power would

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<sup>2</sup> This points to the importance of avoiding over-mitigation, which diminishes the benefits of competitive markets and leads to overly administrative market outcomes, as I discuss in a later section of my affidavit.

still bear the full above-market cost of the uneconomic resource. Thus, it is theoretically possible to exercise buyer-side market power in this manner, but it poses substantial risks to the market participant.

### ***Retaining an existing uneconomic resource***

12. Relative to the case described above, retaining an existing uneconomic resource could theoretically be a decision made on a year-by-year basis and not require a long-term commitment. However, most aging uneconomic resources are uneconomic precisely because continued operation requires costly capital expenditures. Such capital expenditures are unlikely to be recovered in a single year through reduced costs to the market participant's load interest, and thus are unlikely to be offset unless prices remain suppressed for multiple years. For the same reason explained above, a strategy that is only successful if prices remain suppressed for multiple years poses risks to the market participant.
13. In contrast, a Market Participant with supplier-side market power could more straightforwardly exercise such market power by withholding existing capacity on a one-year basis whenever that action is expected to increase economic profits.
14. In sum, supplier-side market power generally may be exercised on an opportunistic basis and with little to no economic risk to the seller (there are legal and regulatory risks for violating the PJM Open Access Transmission Tariff ("Tariff"), the Federal Power Act, and the Commission's Anti-Manipulation Rule), while buyer-side market power requires significant planning and capital investment and must be carried out successfully over a multi-year period to make economic sense (i.e., for the overall benefits exceed costs). Thus, the risks associated with supplier-side market power are not symmetrical to the risk associated with buyer-side market power.
15. Given the lower risk of buyer-side market power relative to supplier-side, it is reasonable to design a buyer-side market power mitigation mechanism that is more focused. The design of market power mitigation mechanisms necessarily must balance multiple objectives of minimizing false positives (over-mitigation), minimizing false negatives (under-mitigation), and minimizing administrative burden to PJM and market participants. The definitions provided above are sufficiently broad as to allow PJM to mitigate any clear cases of Exercise of Buy-Side Market Power, without requiring PJM to over-mitigate cases which are not Exercises of Buyer-Side Market Power.

### **The Existing MOPR Is Too Broad To Accurately Mitigate Buyer-Side Market Power**

16. The existing MOPR goes far beyond addressing the exercise of buyer-side market power. It applies to nearly all resources supported by state actions or subsidies—without consideration of whether the seller has the ability or the incentive to exercise buyer-side market power. It applies even when such state subsidies are economic and welfare enhancing for that state. Rather than restoring the competitive outcome, it distorts market outcomes away from the competitive outcomes that would prevail if the externalities were priced directly in the markets. And continued application of the existing MOPR will cause a growing discrepancy between the resources reflected in market clearing outcomes and

the underlying supply and demand fundamentals, as discussed by Mr. Keech. This will result in excess capacity and ultimately harm customers.

17. Today, state policies often address externalities that are not accounted for in the PJM markets. For example, the historic lack of federal policy in the area of decarbonization has forced multiple states to rationally search for alternatives to ensure the value of carbon-free resources is reflected in the revenues those resources receive. Such policies are second-best alternatives to including the social cost of carbon directly in electricity markets, but they are successful in ensuring the differentiated value between carbon-emitting and carbon-free resources is recognized. Importantly, such policies can be entirely supported on economic grounds as welfare-enhancing. Thus, even if they have the ancillary effect of lowering market prices, there is no reason to suspect that they represent an exercise of buyer-side market power.<sup>3</sup> This is also true for other state policies aimed at addressing externalities not priced in the PJM markets.
18. Beyond the application of MOPR to state policy resources, the existing MOPR also applies widely to new natural gas resources. This application is similarly too broad. It can erroneously apply MOPR to Capacity Market Sellers with no buyer-side market power and replace offers that reflect competitive costs with administratively-determined floors that inaccurately reflect costs. This increases costs to consumers and erodes the efficiency of the market.

#### **Targeted Scope of the New Focused MOPR Proposal**

19. The new MOPR proposal focuses the scope of MOPR to those cases when PJM (or the Independent Market Monitor (“IMM”)) explicitly identifies potential Exercises of Buyer-Side Market Power. Traditional buyer-side market power is still adequately mitigated under the new proposal. PJM plans to investigate when it suspects the potential for the Exercise of buyer-side market power. If, based on its investigation, PJM determines that a Capacity Market Seller may submit an offer that would be an Exercise of Buyer-Side Market Power, PJM will apply the MOPR to relevant Generation Capacity Resource.
20. PJM’s proposed, more focused MOPR calls for PJM or the IMM to investigate the potential Exercise of Buyer-Side Market Power upon articulable basis for inquiry regarding the potential Exercise of Buyer-Side Market Power. An inquiry may be initiated if a Capacity Market Seller intends to offer a resource or technology believed to be uneconomic, in a location where the seller and/or its affiliates have a net short position (that is, more load than generation in a given Locational Deliverability Area (“LDA”)). These elements are indicative of incentive and ability to suppress prices, and may indicate intent to offer below a competitive level. For example, if a seller with a load interest in a highly constrained LDA (and that is net short on generation in that LDA) intended to offer a large coal-fired

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<sup>3</sup> Further, the reduction of capacity prices should not be interpreted as a harmful secondary impact of one state’s policies on other states. Rather, the reduction in prices is a natural consequence of the PJM market appropriately reflecting state policies and customer preferences for certain types of resources. Such state subsidies only lower total costs for consumers in other states.



resource in such LDA, then an inquiry would be initiated, and PJM would articulate the basis in the notice initiating the inquiry.

21. Upon initiating the inquiry, and as part of the investigation, PJM would conduct a detailed review to identify whether each of the three elements from the definition of “Exercise of Buyer-Side Market Power” are met. If the investigation shows that a Capacity Market Seller intends to offer a resource below a level that is identified as reflecting the competitive level, and the Capacity Market Seller also possesses the ability and incentive to suppress prices, PJM would apply the MOPR. I explain next how PJM proposes to test for the presence of ability and incentive to suppress prices, and whether the seller would act to commit an Exercise of Buyer-Side Market Power.

#### *Ability to suppress price*

22. PJM will perform 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, given expected supply and demand conditions in the relevant LDAs and regional transmission organizations (“RTO”). The tests will reflect the expected price elasticity of supply and price elasticity of demand—that is, the sensitivity of the quantity supplied and demanded to changes in price. The tests will also consider whether the relevant LDAs have been constrained in recent RPM Auctions, as this affects the extent to which changes in supply can impact price. The tests will also reflect reasonably expected material changes in an LDA including changes in the modeling of the LDA (i.e., assumptions about capacity import capabilities into an LDA) and expected changes in supply and demand for the applicable Delivery Year. This test is designed to reasonably estimate the extent to which the market participant could suppress prices by offering an uncompetitive resource below its economic cost. For example, consider a new Generation Capacity Resource that has 800 MW of Unforced Capacity (“UCAP”) and will be constructed in a small constrained LDA, like BGE--where 2,866.2 MW were offered in the last BRA (for the 2022/2023 Delivery Year) and 2,494.5 MW cleared. An uneconomic sell offer for such Generation Capacity Resource likely would have the ability to materially reduce the clearing price by displacing nearly 800 MWs of UCAP that had cleared in the previous BRA, reducing the clearing price from \$126.50/MW-day to \$87.98/MW-day. By contrast, assume a 20 MW resource located in central Pennsylvania (the “Rest of RTO” region), where 144,477.3 MW cleared the last BRA. An uneconomic Sell Offer for such Generation Capacity Resource likely would not be able to materially affect the clearing price. The price impact of such a suppressed resource offer would have been precisely \$0/MW-day in the last auction.

#### *Incentive to suppress price*

23. PJM will conduct an ex-ante test to determine whether, given the ability to suppress prices identified in the relevant LDAs and RTO, such price suppression would be economically beneficial to the participant. PJM would compare the expected cost of suppressing the price with the portfolio benefit of doing so. The expected cost will reflect the implied subsidy on the resource in question, where the implied subsidy is the expected excess economic cost of the resource above expected market revenues. The expected benefit will reflect the seller’s (or associated load interests’) expected net short position (in the delivery

year) in the relevant LDAs and RTO multiplied by the price change resulting from offering the resource uneconomically.<sup>4</sup> This approach appropriately reflects whether a Capacity Market Seller has the incentive to suppress market prices: the test will indicate the existence of incentive when suppressing prices is profitable. Conversely, the test will indicate the lack of incentive when a non-competitive offer is not expected to cause a sufficient benefit to the net load position to cover the lost revenues from the below-cost offer. To perform this test, PJM anticipates that it will require cost and revenue data from the seller similar to that provided in the process for determining a unit-specific MOPR Floor Offer Price.

### *Uneconomic behavior to suppress price*

24. As a component of the incentive test described above, PJM will review whether there is any offer level (and resulting clearing prices) at which the seller would obtain an overall benefit to the its portfolio, and which would be uneconomic for a on a standalone basis. The starting point for determining the economically justifiable offer level would be the default MOPR Floor Offer Price, or unit-specific MOPR Floor Offer Price, if elected by the seller, as these reflect avoidable going forward costs net of expected revenues. In addition, PJM will consider additional rationales provided by the Capacity Market Seller to support a resource offer as competitive. An offer that is only economically rational when considering the benefit of price suppression to the participant’s portfolio would be interpreted as evidence of intent to suppress prices below the competitive level.
25. PJM proposes to state in the Tariff several situations that would exempt Capacity Market Sellers from application of the MOPR, as they represent examples of when one or more of the elements of “Exercise of Buyer-Side Market Power” are not present. Below, I quote and elaborate upon each of the proposed Tariff examples:
  - a. “Generation Capacity Resource [that] is a merchant generation supply resource and is not contracted to an entity with a Load Interest.”<sup>5</sup>

A merchant seller does not have a load interest, and price suppression would lower profits to their generation resource(s). Thus, such a seller cannot have the incentive to suppress prices.
  - b. “Generation Capacity Resource 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.”<sup>6</sup>

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<sup>4</sup> The net short position should be calculated to reflect the amount by which the seller’s estimated capacity supply obligations exceed their owned and contracted capacity. It is also necessary to account for capacity obligations in which the capacity costs are based on RPM auction clearing prices and are directly passed through to load, as the seller does not benefit from capacity price suppression for that portion of their obligation. Symmetrically, it is necessary to account for any contracted capacity in which the contract price passes through RPM auction clearing prices.

<sup>5</sup> Proposed Tariff, Attachment DD, section 5.14(h-2)(2)(b)(ii).

<sup>6</sup> *Id.*

As the procurement process is open to new and existing resources, it is unlikely to result in constructing (of new) or retaining (of existing) resources that would otherwise not enter or exit the market. Instead, the lowest-cost offers are most likely to be from those resources that planned to be in the market regardless of the procurement. As this would not change the overall shape of the supply curve, a Capacity Market Seller would not have the ability to suppress prices with these resources.

- c. “Generation Capacity Resource owned by or bilaterally contracted to a Self-Supply Entity and such resource is demonstrated as consistent with or included in the Self-Supply Entity’s long-range resource plan (e.g., a long-range hedging plan) that is approved or otherwise 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.”<sup>7</sup>

Self-supply entities construct and/or enter into long-term contracts for resources to maintain a relative balance between supply and demand. These entities and their customers benefit from relatively stable costs primarily reflecting their cost to maintain such a portfolio, rather than volatile costs reflecting large capacity purchases at uncertain prices from the PJM capacity market. It is economic for such an entity to make long-term plans, and to offer resources consistent with these plans into the capacity market. Thus, self-supply entities that take actions consistent with their independently approved long-range business plans, provided that they do not direct bidding behavior to lower prices, would not be subject to MOPR.

26. Finally, any compensation for or recognition of characteristics aligned with well-demonstrated customer preferences should be recognized as supporting the economics of a resource and may be reflected in resource offers. Capacity Market Sellers may have customers with preferences, or privately-ascribed value, for certain resource types. Even if those preferences are not or cannot be reflected directly through the market, it is value-maximizing to consider these preferences when offering resources. For example, a market participant may rationally be willing to accept lower PJM capacity revenues for a resource that provides additional value to its customers; disallowing this in the market could result in a lower-value resource clearing instead. Similarly, a contracted capacity resource may receive compensation for resource attributes valued by customers but not directly valued in the market. Thus, PJM considers that offers may reflect such private or privately-ascribed value for resource attributes not reflected in the market. An offer reflecting its customers’ preference for the resource (or its particular attributes) would not constitute Exercise of Buyer-Side Market Power: Exercise of Buyer-Side Market Power requires a seller to “uneconomically lower capacity market offers,” but an offer reflecting costs and considering privately ascribed value and compensation characteristics aligned with

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<sup>7</sup> *Id.*

customer preferences would not be uneconomic. Thus, the elements of Exercise of Buyer-Side Market Power are not present.

**It Is Reasonable to Retain Net CONE for New Resources and Net ACR for Previously Cleared Resources**

27. As explained above, a MOPR will still be applied in certain narrow circumstances. For this purpose, PJM proposes to retain the existing MOPR's distinction between new resources and previously cleared resources. In my opinion, this approach is reasonable.
28. The purpose of the proposed MOPR is to mitigate buyer-side market power and the impact of improper state intrusions on capacity market price formation by returning the capacity market clearing outcomes to those that would prevail in the absence of non-competitive offers. Such offers would otherwise distort market outcomes away from the competitive outcome. The competitive outcome is characterized by market prices that equal the marginal value of incremental capacity (as defined by the demand curves), with the total demand met by resources whose economic costs of supplying capacity are less than or equal to the market clearing price. A resource's economic costs of supplying capacity includes all going-forward avoidable costs of capacity, net of energy, ancillary services, and other revenues the resource may receive. Going-forward avoidable costs exclude costs that would not be avoided if the resource did not provide capacity in the Delivery Year.
29. To accomplish its purpose of re-instating competitive market outcomes, the MOPR should be applied at a level that reflects the competitive offer whenever a distortive resource offer is identified. The competitive offer level is that which would be chosen by a competitive Capacity Market Seller, i.e., a seller which lacks either the ability or the incentive to raise or lower market-clearing prices. Naturally, a competitive market participant should choose to offer their resources at prices that reflect economic costs (net avoidable going forward costs) as this offer level maximizes profits. Offers above this level may lead to lost revenues if the resource does not clear but prices are higher than their economic costs, while offers below this level may lead to a resource clearing and not receiving sufficient revenues to cover economic costs.
30. For existing resources, PJM estimates economic costs as the Net Avoidable Cost Rate ("ACR"). This level reflects primarily annual fixed operating costs (net of other market revenues), which could be avoided by mothballing or retiring the resource. For existing resources, no portion of sunk capital costs are included in the competitive offer as those costs would not be avoided by avoiding a capacity supply obligation in the delivery year. A competitive Capacity Market Seller of an existing resource may be worse off by including sunk capital costs in their offer, if those costs cause their offer not to clear the market. In such a case, the seller would lose market revenues while not avoiding paying sunk costs.
31. For new resources, PJM estimates economic costs as the Net CONE. This level reflects year one fixed operating costs plus amortized year one construction and financing costs. For new resources, capital costs *are* included in the competitive offer as those costs indeed would be avoided by choosing not to construct the new resource nor accept a capacity

supply obligation. Any costs already expended (sunk) by a new entrant would be included in the calculation of the Net CONE, as this reflects the competitive, economic offer level of a resource by a competitive participant whose entry decision is informed by market outcomes (that is, whether the resource clears the capacity market or not).

32. Applying the MOPR at Net ACR for a new resource would not reflect the competitive offer price at which the market participant would choose to construct. For example, a competitive Capacity Market Seller whose prospective resource has high costs would not plan to enter the market where going forward revenues are insufficient to cover all costs plus a return on investment. Such a competitive Capacity Market Seller would either offer substantially above Net ACR, or not offer at all. This is the competitive outcome that PJM would endeavor to reproduce by applying MOPR at Net CONE to new resources when Capacity Market Sellers are found to be exercising Buyer-Side Market Power.
33. This concludes my affidavit.



# Attachment F

Affidavit of Lisa Morelli  
on behalf of PJM Interconnection, L.L.C.





and Non-Synchronized Reserve Markets in addition to the Real-Time Security Constrained Economic Dispatch tool used by PJM's system operators.

4. I have worked at PJM since October 2004. I hold a Bachelor's degree in Business Administration from LaSalle University in Philadelphia, PA and a Master's degree in Business Administration from Villanova University in Villanova, PA.
5. My affidavit supports PJM's filing of Tariff revisions and provides an overview of the proposed replacement MOPR

## **I. PJM PROPOSAL OVERVIEW AND PREMISE**

6. In this proceeding, PJM proposes to change the current Minimum Offer Price Rule from one that broadly targets any out-of-market action that may result in price suppression to one that seeks to more surgically mitigate attempts to exercise buyer-side market power, as well as state policies that improperly interfere with FERC's exclusive authority to regulate wholesale rates. In addition, PJM proposes to switch the paradigm away from the current MOPR's presumption of guilt (i.e., a presumption of mitigation) and resulting over-mitigation to one of presumed innocence (provided appropriate certifications are made), with specific triggers for mitigation where necessary.
7. In general, PJM's proposal is designed to accomplish three primary objectives:
  - a. mitigate attempted exercises of buyer-side market power and offers from resources receiving conditioned state support,
  - b. accommodate state policies to the extent they are not considered conditioned state support and accommodate self-supply business models to the extent their actions are not an attempt to exert buyer-side market power, and
  - c. align market commitments and clearing prices with the underlying supply and demand fundamentals of the capacity market so the rules result in a sustainable market design.
8. To accomplish these objectives, the PJM proposal uses two certifications that identify: (1) whether the seller is receiving revenues from a state policy or program that qualifies as Conditioned State Support, as defined in the PJM proposal, and (2) whether a seller's offers are intended to lower market clearing prices to benefit their overall portfolio or the portfolio of an entity with which they have bilaterally contracted. While PJM's proposal contains provisions for a secondary review of the matters addressed by these certifications, such certifications by Market Sellers will be presumed accurate, unless a detailed fact-specific review reveals otherwise.
9. PJM chose to use certifications as a first step in its proposal because it would be overly burdensome for PJM to annually identify and study each state policy or program that provides a benefit to a market seller and determine if it meets the defined criteria of

Conditioned State Support, or to determine whether each market seller without an obvious load obligation of its own has the incentive to exercise buyer-side market power. Indeed, requiring all market sellers to submit their data and bilateral contracts to PJM, and requiring PJM to review all of these data and contracts to make a determination on whether to apply the MOPR for each resource, would be a considerable amount of additional—and unnecessary—work for both PJM and market sellers. As a result, PJM proposes to carry forward the existing state subsidy MOPR certification framework as a simple yet effective means to identify attempts to exercise buyer-side market power. The certification requirement places the onus on the market seller to provide a truthful representation of their arrangements and may result in referrals to FERC or the Market Monitor if the market seller intentionally makes a misrepresentation.

## II. CONDITIONED STATE SUPPORT

10. The certification regarding support stemming from state policy requires the market seller to identify if they are receiving revenues pursuant to a state policy or program that meets PJM’s proposed definition of Conditioned State Support.
11. Specifically, PJM proposes to define Conditioned State Support as
  - any financial benefit required or incentivized by a state, or political subdivision of a state acting in its sovereign capacity, that is provided outside of PJM Markets and in exchange for the sale of a FERC-jurisdictional product conditioned on clearing in any RPM Auction, where “conditioned on clearing in any RPM Auction” refers to specific directives as to the level of the offer that must be entered for the relevant Generation Capacity Resource in the RPM Auction or directives that the Generation Capacity Resource is required to clear in any RPM Auction. Conditioned State Support shall not include any Legacy Policy.
12. “Conditioned” in this context indicates payment for a FERC-jurisdictional product, such as energy or capacity, is contingent on either the resource clearing in the market or otherwise following state-specified directives as to the price level at which the market seller must offer a resource into the market. The latter condition is to ensure that policies that do not explicitly require clearing in the market, but require bidding at \$0, or some other offer, would still trigger the definition of conditioned state support. The “Conditioned” criteria are derived from the U.S. Supreme Court’s decision in the *Hughes* case<sup>2</sup> where the Supreme Court ruled that states may not intrude on FERC’s authority over interstate wholesale rates.
13. The specific certification language that Capacity Market Sellers are expected to attest to for Conditioned State Support is as follows:

By submitting “Yes”, the Capacity Market Seller certifies that this Generation Capacity Resource is receiving or expected to receive

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<sup>2</sup> *Hughes v. Talen Energy Marketing, LLC*, 136 S. Ct. 1288 (2018) (“*Hughes*”).

Conditioned State Support under any legislative or other governmental policy or program that is effective at the time of this certification. By submitting “No”, the Capacity Market Seller certifies that Generation Capacity Resource is not receiving or expected to receive Conditioned State Support under any legislative or other governmental policy or program that is effective at the time of this certification.

14. Application of the MOPR in these instances is appropriate because the state would be improperly intruding on price formation in the wholesale capacity market. Through the conditions, the state is setting what it thinks the capacity rate should be, regardless of the supply/demand fundamentals and FERC market rules. Aside from being unlawful, this can distort market outcomes if the resource would be uneconomic absent such state support. As courts have found, there are numerous ways for states to provide support for desired resources without interfering with the price. In addition, because PJM has closely tailored its Conditioned State Support criteria on the *Hughes* case, such state action is likely to be found to be a pre-empted state policy upon challenge in the courts. Rather than allow such an offer into the market or disqualify the unit from participating in the capacity market, PJM’s proposal applies the MOPR to ensure that if the resource is economic based on an offer price that does not include the impact of the questioned state policy, the resource is permitted to clear. This outcome still permits the resource to provide capacity in PJM if it is economic, but does not allow the questioned state policy to improperly influence the offer and by extension the market clearing price. It is reasonable to apply the MOPR in such circumstances to proactively protect the capacity market outcomes from the influence of state policies that would improperly intrude on the capacity market and that have a high likelihood of being nullified by the courts.
15. PJM does not propose to make the final determination of which state policies constitute Conditioned State Support. Rather, the Commission should be the arbiter of such jurisdictional issues. Accordingly, upon review of market seller certifications regarding Conditioned State Support (and also based on PJM’s own knowledge and understanding), PJM will identify, in a Federal Power Act (“FPA”) section 205<sup>3</sup> filing, for Commission review those state policies and programs that may qualify as Conditioned State Support. PJM intends to make such a filing sufficiently prior to each auction (e.g., about 110 days) to allow the Commission time to review and act on the filing prior to the applicable RPM Auction. If the Commission finds that such policy or program constitutes Conditioned State Support, any resources receiving support from such policy or program will be subject to the MOPR and thus will not be permitted to submit an offer price lower than the applicable MOPR Floor Offer Price.
16. PJM’s proposed process for determining Conditioned State Support is reasonable because:
  - a. The core question at hand in these cases is one of jurisdiction and PJM is not the appropriate entity to determine whether the jurisdictional boundaries between FERC and a state have been crossed.

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<sup>3</sup> 16 U.S.C. § 824d.

- b. It is likely that PJM’s classification of a state policy or program as Conditioned State Support will be subject to protest by the state, the market seller, and/or other interested parties. Rather than have litigation occur during or after an auction, it is appropriate for the Commission to resolve these issues prior to the conduct of the auction, and thereby minimize the chance that the auction results may be called into question due to an improper application (or lack of application) of the MOPR.
17. To provide greater certainty for market participants and stakeholders, the PJM proposal explicitly highlights examples of state policies in existence today that do not constitute Conditioned State Support, because they do not explicitly pay for a FERC-jurisdictional product, or because they neither condition payment on clearing in the capacity market nor direct the level at which such resources must be offered into the market. Specifically, the programs listed below are examples of state policies that would not be deemed Conditioned State Support as they exist today and would, therefore, not require resources receiving support through them to be subject to MOPR:
- a. Non-FERC jurisdictional programs such as renewable energy credits/zero emission credits/regional emissions greenhouse gas initiative
  - b. State and local tax incentives
  - c. State retail default service auctions
  - d. Incentives related to fuel supplies
  - e. Federal regulatory programs administered by states such as the Public Utilities Regulatory Act and the Cross-State Air Pollution Rule
18. To be clear, the triggers for classifying a state policy or program as Conditioned State Support are simply whether: (1) the payment or other financial compensation is being provided outside of PJM’s market for the sale of a FERC-jurisdictional product and (2) the policy or program requires that the unit clear in any capacity auction or directs the price level at which the unit must be offered into the capacity market. If a policy or program appears to meet these two criteria, PJM will submit an FPA section 205 filing to seek the Commission’s approval of whether the policy or program, in fact, constitutes Conditioned State Support.

***Exemption for Existing State Policies from the Definition of Conditioned State Support***

19. PJM is proposing a one-time exemption from the MOPR for any existing state policies that may meet the criteria for Conditioned State Support. The exemption applies to any state legislative, executive, or other regulatory action that was in effect prior to October 1, 2021. PJM’s exemption only regards application of the MOPR and does not purport to address whether any existing policies are pre-empted by federal law.
20. In essence, this exemption provides the States a “clean slate” and allows for a prospective application of the new MOPR. This is consistent with Commission precedent, most

notably in the December 2019 order on PJM's state subsidy MOPR, where the Commission ordered MOPR exemptions for several classes of existing resources, including renewables, storage, demand response, and those owned by Self-Supply Entities. As there, the purpose here is to set a new rule and apply it prospectively.

### **III. BUYER-SIDE MARKET POWER**

21. As I stated previously, PJM's MOPR proposal is narrowly tailored to address actual attempts to exert buyer-side market power and moves away from the current rule, which over-mitigates even those offers that are not intended to exert buyer-side market power. To accomplish this, the proposed buyer-side market power MOPR provisions have three components.
  - a. A clear, simple, definition of buyer-side market power that will be memorialized in the Tariff.
  - b. A certification from market sellers that their offers are not submitted with an intent to exert buyer-side market power.
  - c. An opportunity for PJM and/or PJM's Independent Market Monitor ("IMM") to review the facts regarding any certification, as needed. In the event PJM and/or the IMM have reason to inquire whether the certification was not made truthfully.
22. Dr. Graf provides more detail and explanation regarding how the new, more narrowly-tailored MOPR will mitigate buyer-side market power. Below, I focus on certain procedural and mechanical aspects of PJM's buyer-side market power mitigation proposal.

#### ***Certification Requirement for Buyer-Side Market Power***

23. The certification aspect of the PJM proposal requires each market seller to certify through PJM's Capacity Exchange application that their offers into the capacity market are not submitted with the intent of exercising buyer-side market power. As I explained earlier, PJM does not have record of every bilateral contract struck between members and requiring such information from all market sellers would be unduly burdensome and disruptive to the market. As such, the PJM proposal puts the onus on the market seller to accurately represent their offer motivations and bilateral agreements. Specifically, the single certification will focus on two items:
  - a. Acknowledgement that the market seller knows the prohibitions against the exercise of buyer-side market power in the PJM Tariff and their offers are not an attempt to exert it.
  - b. Certification that the market seller is not engaged in any bilateral transactions that direct the bidding behavior of the market seller in a manner that is intended to deliberately lower clearing prices.

24. The specific certification language that Capacity Market Sellers are expected to attest to for Buyer-Side Market Power is as follows:

By submitting “Yes”, the Capacity Market Seller acknowledges the prohibition of the Exercise of Buyer Side Market Power and does not intend to Exercise Buyer-Side Market Power for this Generation Capacity Resource. By submitting no, the Capacity Market Seller does not certify to the above statement.

25. The motivations captured by this certification aligns with the definition of buyer-side market power as it applies specifically in the capacity market context. If a market seller certifies that its offers will not be influenced by the aforementioned motivations, generally, that market seller will be granted a presumption of good faith. If the market seller cannot provide such certification, then their resources will be subject to the MOPR. I specifically used the term “generally” here because of the fact-specific review of each resource, in response to the certifications that may be performed by PJM and/or the IMM. I will further describe that process in the next section.
26. The certifications will be required by 150 days prior to the auction window to give PJM sufficient time to review certifications and notify the market participant of any certifications that may have been erroneously designated by 135 days prior to the relevant RPM Auction. This ensures Capacity Market Sellers that may have Buyer-Side Market Power and may be subject to MOPR will have an opportunity to seek a unit-specific MOPR floor price prior to the 120 day unit-specific exception request deadline.

#### **IV. FACT-SPECIFIC REVIEW FOR EITHER CONDITIONED STATE SUPPORT OR EXERCISE OF BUYER-SIDE MARKET POWER**

27. On occasion, PJM and/or the IMM may believe there is a need to follow-up with a market participant regarding their certification to double-check whether it was completed correctly or to investigate the facts and circumstances of the certification. PJM plans to perform this after-the-fact review when there is reasonable basis for inquiring as to whether the certification was done incorrectly, not as a common practice. The factors that may trigger an inquiry for the Conditioned State Support certification include but are not limited to where:
- a. Two resources that are eligible for the same revenues from a state policy but the owners make different certifications.
  - b. A resource that is receiving revenues from a state policy or program that could be considered conditional state support but the market seller certifies that they are not receiving revenues from such a policy or program.
28. If these cases are uncovered, the first course of action would be to have a conversation with the market seller to understand the facts and circumstances supporting their certification and identify any further details about the certification that may cause PJM to believe it was made incorrectly. Should PJM determine that the certification was made incorrectly, PJM

will notify, in writing, the market participant of its determination and state why it came to that conclusion. Then PJM will proceed to submit to the Commission an FPA section 205 filing based on its interpretation of the state policy or program, if such determination had not been previously made by the Commission. If the Commission has already found that the state policy or program is a form of Conditioned State Support, PJM will apply the MOPR to any Sell Offer made as to a resource receiving revenue from such policy or program. Should PJM, with advice and input from the IMM, suspect that a certification was intentionally made incorrectly, PJM will refer that seller to the FERC Office of Enforcement.

29. For the buyer-side market power certification, the factors that may trigger a fact-specific review are different. In these circumstances, the factors are those that could indicate an attempt to exert buyer-side market power despite a certification to the contrary. The factors in this scenario include:
  - a. A market seller with a large purchase position in a constrained Locational Deliverability Area (“LDA”). The relevant size of the purchase position will change with the size of the LDA and slope of the applicable demand curve. The smaller the LDA, the steeper the demand curve and therefore the smaller the size of the purchase position needed to effectively exert buyer-side market power;  
  
*and*
  - b. If this market seller is also planning to offer a specific resource or technology that is deemed to be uneconomic based on publicly available data, or through an observed lack of merchant investment in the technology, the seller may be subject to an inquiry whether it may be suppressing market prices through uneconomic investment.
30. While these criteria are high-level, the purpose of this process is to trigger a fact-specific review where more detail can be shared on the specific scenario, not to use the above factors as an outright determination. Therefore, PJM expects more information to be shared through this process as it is intended to provide the market seller with an opportunity to provide evidence to support their certification. The fact-specific review process is described in detail in Dr. Graf’s affidavit.
31. This concludes my affidavit.

**UNITED STATES OF AMERICA  
BEFORE THE  
FEDERAL ENERGY REGULATORY COMMISSION**

**PJM Interconnection, L.L.C.**

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**Docket No. ER21-\_\_\_\_-000**

**VERIFICATION**

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



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Lisa Morelli  
Director, Market Design  
PJM Interconnection, L.L.C.



# Attachment G

Comparison of section  
Focused MOPR default and unit-specific MOPR  
Floor Offer Prices determinations  
against Expanded MOPR default and unit-specific  
MOPR Floor Offer Prices determinations

~~h-1h-2~~) Minimum Offer Price Rule ~~for Capacity Resources Effective~~ with State Subsidy ~~the 2023/2024 Delivery Year~~

~~(2)~~ **(3) Minimum Offer Price Rule.** Any Sell Offer for a ~~New Entry Generation~~ 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 that is subject to the provisions of the~~ Minimum Offer Price Rule pursuant to Tariff, Attachment DD, ~~sections 5.14(h-1)(4) (8), 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 ~~Resource with State Subsidy must seek a resource-specific~~ Market Seller, to participate in an RPM Auction, must request a unit-specific value determined in accordance with the ~~resource-specific-unit-specific~~ MOPR Floor Offer Price process to participate in an RPM Auction, 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 ~~New Entry Capacity Resource with State Subsidy~~ 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 ~~each the~~ resource type, shall be, at the election of the Capacity Market Seller, (i) the ~~resource-specific-unit-specific~~ value determined in accordance with the ~~resource-specific-unit-specific~~ MOPR Floor Offer Price process in Tariff, Attachment DD, section ~~5.14(h-1)(3) 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 Delivery Year, net of estimated net energy and ancillary service revenues for the resource type and Zone in which the resource is located.

Resource Type	Gross Cost of New Entry (2022/2023 \$/ MW-day) (Nameplate)
Nuclear	\$2,000
Coal	\$1,068
Combined Cycle	\$320
Combustion Turbine	\$294
Fixed Solar PV	\$271
Tracking Solar PV	\$290
Onshore Wind	\$420
Offshore Wind	\$1,155
Battery Energy Storage	\$532
<del>Diesel Backed Demand Resource</del>	<del>\$254</del>

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~~ 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.

~~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.~~

Commencing with the Base Residual Auction for the 2023/2024 Delivery Year, the Office of the Interconnection shall adjust the default gross costs of new entry in the table above ~~and for load-backed Demand Resources,~~ and post the preliminary estimates of the adjusted applicable default New Entry MOPR Floor Offer Prices on its website, by no later than one hundred fifty (150) days prior to the commencement of the offer period for each Base Residual Auction. To determine the adjusted applicable default New Entry MOPR Floor Offer Prices for all resource types ~~except for load-backed Demand Resources and Energy Efficiency Resources,~~ the Office of the Interconnection shall adjust the gross costs of new entry utilizing, for combustion turbine and combined cycle resource types, the same Applicable BLS Composite Index applied for such Delivery Year to adjust the CONE value used to determine the Variable Resource Requirement Curve, in accordance with Tariff, Attachment DD, section 5.10(a)(iv), and for all other resource types, the “BLS Producer Price Index Turbines and Turbine Generator Sets” component of the Applicable BLS Composite Index used to determine the Variable Resource Requirement Curve shall be replaced with the “BLS Producer Price Index Final Demand, Goods Less Food & Energy, Private Capital Equipment” when adjusting the gross costs of new entry. The resultant value shall then be then adjusted further by a factor of 1.022 for nuclear, coal, combustion turbine, and combine cycle, ~~and generation-backed Demand Resource- 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; and

(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.~~

Beginning with the Delivery Year that commences June 1, 2022, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall review the default gross cost of new entry values. Such review may include, without limitation, analyses of the fixed development, construction, operation, and maintenance costs for such resource types. Based on the results of such review, PJM shall propose either to modify or retain the default gross cost of new entry values stated in the table above ~~and the default gross cost of new entry value for Energy Efficiency Resources~~. The Office of the Interconnection shall post publicly and solicit stakeholder comment regarding the proposal. If, as a result of this process, changes to the default gross cost of new entry values are proposed, the Office of the Interconnection shall file such proposed modifications with the FERC by October 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

~~New Entry Capacity Resource with State Subsidy~~ 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 ~~resource-specific-unit-specific~~ value determined in accordance with the ~~resource-specific-unit-specific~~ MOPR Floor Offer Price process below to participate in an RPM Auction. Failure to obtain a ~~resource-specific-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 ~~Cleared Capacity Resource with State Subsidy~~ 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 ~~resource-specific-unit-specific~~ MOPR Floor Offer Price-, as determined in accordance with Tariff, Attachment DD, section ~~5.14(h-1)(3)~~ 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 Delivery Year 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 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
<del>Diesel-backed Demand Response</del>	<del>\$3</del>
<del>Load-backed Demand Response</del>	<del>\$0</del>
<del>Energy Efficiency</del>	<del>\$0</del>

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. 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 ~~Resources with State Subsidies~~ 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 ~~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~~ 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 ~~resource-specific-unit-specific~~ value determined in accordance with the ~~resource-specific-unit-specific~~ MOPR Floor Offer Price process below to participate in an RPM Auction. Failure to obtain a ~~resource-specific-unit-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)~~ 5.14(h-2)(3)(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 Generation~~ Capacity Resource ~~with State Subsidy that has previously cleared an RPM Auction for any Delivery Year and where such Sell Offer is~~ 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-unit-specific~~ MOPR Floor Offer Price for such Capacity Resource pursuant to Tariff, Attachment DD, section ~~5.14(h-1)(3)5.14(h-2)(4)~~ below.

~~(3)(4) Resource-Specific-Unit-Specific Exception.~~ A Capacity Market Seller intending to submit a Sell Offer in any RPM Auction for a ~~New Entry-Generation~~ Capacity Resource ~~with State Subsidy or a Cleared Capacity Resource with State Subsidy 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 ~~resource-specific-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 ~~resource-specific-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 ~~resource-specific-unit-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-unit-specific~~ Accredited UCAP value for ~~ELCC Resources (where battery energy storage resource types and~~ 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- 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 ~~were of~~ 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-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-1)(2)(A)~~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 ~~resource-specific-unit-specific~~ exception for a New Entry Generation Capacity Resource ~~with State Subsidy 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 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 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 ~~resource-specific-unit-specific~~ exception hereunder. The request also shall identify all revenue sources (exclusive of any ~~State Subsidies~~ 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. 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-unit-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-Unit-Specific~~ Exception for a ~~Cleared Generation~~ Capacity Resource with State Subsidy that is a generation 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 ~~State Subsidies~~ 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-unit-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-unit-specific~~ exception shall be permitted if the information provided reasonably demonstrates that the Sell Offer's competitive, ~~fixed, cost-based, fixed, net cost of new entry- 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 ~~costs-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 ~~denial of a resource-specific~~ 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 ~~resource-specific-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 ~~resource-specific-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 ~~resource-specific-unit-specific~~ determination unless and until ordered to do otherwise by FERC.